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# TAX TREATMENT OF PRODUCERS OF OIL AND GAS

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## HEARINGS

BEFORE THE

SUBCOMMITTEE ON OVERSIGHT

OF THE

COMMITTEE ON WAYS AND MEANS
HOUSE OF REPRESENTATIVES

NINETY-EIGHTH CONGRESS

FIRST SESSION

MAY 5 AND 6, 1983

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# TAX TREATMENT OF PRODUCERS OF OIL AND GAS

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THURSDAY, MAY 5, 1983

House of Representatives,
Committee on Ways and Means,
Subcommittee on Oversight,
*Washington, D.C.*

The subcommittee met at 10:10 a.m., pursuant to notice, in room 1100, Longworth House Office Building, Hon. Charles B. Rangel (chairman of the subcommittee) presiding.

[The press release announcing the hearings follows:]

[Press Release of Friday, April 15, 1983]

Hon. Charles B. Rangel (D., N.Y.), Chairman, Subcommittee on Oversight, Committee on Ways and Means, U.S. House of Representatives, Announces Hearings on the Tax Treatment of Producers of Oil and Gas on Thursday and Friday, May 5 and 6, 1983

The Honorable Charles B. Rangel (D., N.Y.), Chairman of the Subcommittee on Oversight of the Committee on Ways and Means, announced today that the Subcommittee will conduct hearings on the tax treatment of producers of oil and gas on Thursday, May 5 and Friday, May 6, 1983. The hearings will be held in Room 1100 Longworth House Office Building and will begin at 10:00 a.m. each day. These hearings were previously announced (Press Release No. 1) on January 18, 1983, and are being held at the request of the Honorable Dan Rostenkowski, Chairman of the Committee on Ways and Means. The Subcommittee will review the effects of differences in the tax treatment of various types of oil and gas producers.

The following provisions of the Internal Revenue Code provide different tax treatment for different types of oil and gas producers:

(1) An independent producer (i.e., one who does not refine or retail more than a certain amount) may claim percentage depletion on up to 1,000 barrels of oil per day or the equivalent amount of natural gas.

(2) Intangible drilling costs (IDCs) of individuals (but not corporations) are subject to the 20-percent alternative minimum tax. However, individuals may elect to write off their IDCs over 5 years and claim the investment tax credit, in which case the IDCs are not subject to the minimum tax.

(3) Intangible drilling costs of individuals and closely held corporations (but not widely held corporations) are subject to the at-risk rules.

(4) Up to 1,000 barrels per day of crude oil produced by an independent producer are eligible for reduced windfall profit tax rates (from 70 to 50 percent on tier 1 and from 60 to 30 percent on tier 2).

(5) Stripper oil produced by independent producers is exempt from the windfall profit tax.

(6) Up to 2 barrels per day of oil production of qualified royalty owners are exempt from the windfall profit tax (3 barrels per day after 1984).

(7) Corporations who are integrated oil companies may expense 85 percent of their intangible drilling costs. The remaining 15 percent is to be written off over 36 months. Individuals and corporations who are independent producers may expense all of their IDCs.

(8) Integrated oil companies must deposit their windfall profit tax faster than other taxpayers.

The Subcommittee will inquire into the extent to which the present law favors certain kinds of oil and gas producers relative to others, whether tax treatment which is not uniform is good tax and energy policy, and whether the specific provisions providing different treatment work as they were intended.

### DETAILS FOR SUBMISSION OF REQUESTS TO BE HEARD

In addition to testimony received from invited witnesses, individuals and organizations interested in presenting oral testimony at the hearing should submit their requests to be heard by telephone to Harriett Lawler ((202) 225-3627) no later than the close of business, Monday, April 25, 1983, to be followed by a formal written request to John J. Salmon, Chief Counsel, Committee on Ways and Means, U.S. House of Representatives, 1102 Longworth House Office Building, Washington, D.C. 20515. Notification to those scheduled to appear will be made by telephone as soon as possible after the filing deadline.

It is urged that persons and organizations having a common position make every effort to designate one spokesperson to represent them in order for the Subcommittee to hear as many points of view as possible. Time for oral presentations will be limited with the understanding that a more detailed statement may be included in the printed record of the hearing. This procedure will afford more time for Members to question witnesses. In order to expedite the hearing, witnesses may be grouped as panelists with time limitations for each panelist.

Requests to be heard must contain the following information:

(1) The name, address, title, firm affiliation and/or organization the witness will represent (as well as a telephone number where he or his designated representative may be reached);

(2) If appearing in an individual capacity, a list of any clients at whose request or in whose employ the witness appears; and

(3) A topical outline or summary of comments and recommendations.

The above information should also be incorporated in the prepared statements to be presented in person as well as those filed for the written record of the hearing.

In order to assure the most productive use of the limited amount of time available to question hearing witnesses, witnesses scheduled to appear before the Subcommittee are required to submit 50 copies of their prepared statement to the full Committee office, Room 1102 Longworth House Office Building, at least 24 hours in advance of their scheduled appearance. Failure to comply with this requirement may result in the witness being denied the opportunity to testify in person.

### WRITTEN STATEMENTS IN LIEU OF PERSONAL APPEARANCE

For those who wish to file a written statement for the printed record of the hearing, five copies are required and may be submitted to John J. Salmon, Chief Counsel, Committee on Ways and Means, U.S. House of Representatives, Room 1102 Longworth House Office Building, Washington, D.C. 20515, by close of business, May 27, 1983. An additional supply of statements for the printed record may be furnished for distribution to the press and public if supplied to the Committee office before the hearing.

Chairman RANGEL. The Ways and Means Subcommittee on Oversight will come to order.

This morning's hearings will be on the tax treatment of producers of oil and gas.

The relationship between Federal tax policy and oil and gas production is complex and a matter of some controversy.

In the past, debate and congressional review focused on percentage depletion, the expensing of intangible drilling and development costs, and the enactment of windfall profit tax legislation.

More recently, discussion regarding these issues has been conducted in connection with legislation which exempts part of the producer industry, particularly independent producers and royalty owners, from industrywide tax legislation.

Prior to 1975, the tax law treated income received by holders of economic interests in domestic oil and gas properties essentially the same regardless of whether the income was received by an integrated major oil company, an independent producer, or a royalty owner.

Also, tax treatment was uniform regardless of whether the taxpayer was a corporation, partnership, or an individual.

Since that time, Congress has enacted a series of tax provisions that make distinctions between these various types of oil and gas producers. These recent Tax Code changes have been enacted in a piecemeal fashion and have not been reviewed in a comprehensive manner.

The purpose of the hearings today and tomorrow is to receive information and compile a record concerning the nature and basis for differences in tax treatment of oil and gas producers;

The extent to which these differences created special preferences and thus favor certain kinds of oil and gas producers relative to others;

Whether tax treatment which is not uniform among all producers is good tax, economic and energy policy; and

Whether the code provisions which provide differing tax treatment work as intended.

The principal objective of the hearings, therefore, is to receive information, which will assist the subcommittee in analyzing the cumulative effects of the differences in tax treatment, their cost in terms of lost revenue and benefits in terms of increased oil and gas production.

Mr. Duncan?

Mr. DUNCAN. I have no statement. Thank you, Mr. Chairman.

Chairman RANGEL. Are there any members of the subcommittee that would like to make an opening statement?

Mr. Anthony?

Mr. ANTHONY. Thank you, Mr. Chairman.

I just have a short comment to make.

I look forward to the 2 days of hearings and the testimony.

Some of the tax provisions that came, as you say, piecemeal since 1975, I have had an active role in developing, inasmuch as part of my district is oil and gas producing.

In order to try to justify what we think is good energy policy and good tax policy, I have requested some of my constituents to appear before the subcommittee. I look forward to having a four-member panel consisting of Mr. Reynolds, Mr. Lowery, Mr. DeLone, and Mr. Brasher to try and help not only this subcommittee, but the full committee, determine exactly what you stated were the objectives of this hearing.

Not only do I welcome them, but I welcome the other witnesses.

Chairman RANGEL. Mr. Thomas.

Mr. THOMAS. Thank you, Mr. Chairman. I had not intended to make an opening statement.

Let me say briefly that I commend the committee and the subcommittee for holding these hearings. I think it is an important area for us to investigate. However, let me also say that in reviewing the briefing book, which I realize is for subcommittee members, it seems to me that in my brief acquaintance with this committee and this subcommittee, that I ought to let you know that in reviewing this briefing book I found that on the five pages of arguments over the suggested tax changes, every single argument in favor of retaining one of the tax provisions was shorter than those arguments in favor of removing it. That may or may not say anything.

In addition, there was an interesting six-page analysis of the production process in oil, and in those six pages I found four lines on tertiary recovery.

Let me indicate why I found that interesting.

In the glossary which also accompanied it, I assume, to allow members to familiarize themselves with terms in the oil industry, there was no heavy oil definition. Yet in the windfall profits tax one of the major battles that I engaged in when I first came to this Congress was in trying to convince people who apparently didn't know that much about the oil industry that heavy oil ought to be defined at 20 gravity rather than the 16 in the windfall profit tax.

There was no discussion of heavy oil.

Lest this sound somewhat petty, let me put it in proper context.

Appendix I in that same briefing book lists by State the oil production of States. The largest oil-producing State is Texas; the next Alaska; the third Louisiana.

The county that I represent, Kern County, if it were a State, produces enough oil to be listed No. 4 in all of the States in oil production—better than 160,000 barrels a day. Much of that is in heavy oil. We have billions of proven reserves in heavy oil; it is as defined unfairly in the Windfall Profit Tax Act or as defined by the industry as 20 degrees gravity. We have probably reserves of tens of billions of barrels of oil in the heavy oil category.

My concern is, as we get into an examination of independent versus integrated versus other groups that we don't lose sight of the fact that in addition to the different types of producers there is clearly out there different types of oil, because, when you deal with heavy oil, you not only have a higher initial cost of producing the oil, you also have a product which is less attractive in the marketplace.

I have a number of items to indicate pricing of various types of heavy crude and so on. So my concern at the outset is, let's make sure that we focus on a significant resource in the United States; that is, heavy oil.

My concern is that in reviewing the briefing book prepared by individuals on the staff that perhaps we are not as familiar with this resource as possible.

Chairman **Rangel**. Mr. Thomas, I had hoped that members of this subcommittee would have attended the briefing, which I heard you did attend. That would have been the time, I think, to request additional information to be put in a book that is designed to assist members who need help in understanding more clearly the issues.

The reason for having the hearing is so that we can hear from expert witnesses, and not to analyze the shortcomings of staff.

Mr. **Thomas**. My concern is not with the shortcomings of the staff, but in this process I want to emphasize at the beginning that as we review tax measures that apply to the oil and gas industry that we understand that past and prospective practices, and, if we are to engage in a changing of the law, have to understand the differences out there in the industry itself.

Chairman **Rangel**. Mr. Dorgan?

Mr. DORGAN. Thank you, Mr. Chairman. I just want to reiterate the statement of Mr. Anthony. I think that the reasons that we are holding these hearings are important and compelling reasons. I come from a State that ranks about ninth in oil production in the country.

I expect we will have a full discussion on all of the issues. My interest is in trying to develop a fair and workable tax system on the oil industry.

I found the briefing book to be a good book. If there are some deficiencies with respect to all of the arguments on these issues, I expect they will come out fully in 2 days of hearings.

Let me just depart for 1 minute and say publicly what I have felt privately for a long while.

Dr. Rivlin, you have done a superb job. The Government owes you a great debt for your service. I am pleased you are here as the first witness.

Chairman RANGEL. Mr. Pickle from Texas, I assume, has some small interest in this subject matter.

Mr. PICKLE. No opening statement, Mr. Chairman.

Chairman RANGEL. Thank you.

Dr. Rivlin, we appreciate the cooperation you have always given to the committee and subcommittee. We look forward to hearing your testimony. You can identify the people with you and proceed.

## STATEMENT OF ALICE M. RIVLIN, DIRECTOR, CONGRESSIONAL BUDGET OFFICE, ACCOMPANIED BY JAMES VERDIER, ASSISTANT DIRECTOR, TAX ANALYSIS DIVISION; ROBERT LUCKE, ANALYST, TAX ANALYSIS DIVISION; AND EVERETT EHRLICH, DEPUTY ASSISTANT DIRECTOR, NATURAL RESOURCES DIVISION

Ms. RIVLIN. Thank you very much, Mr. Chairman. I am delighted to be here as you tackle an obviously complex issue. I am particularly grateful for Mr. Dorgan's remarks.

Let me introduce my colleagues. On my extreme left, James Verdier, head of our Tax Analysis Division.

Next to him, Bob Lucke, who has done most of the work on this particular statement.

And, on my right, Everett Ehrlich, from our Natural Resources Division.

Mr. Chairman, at the request of this committee the Congressional Budget Office has examined several of the tax code provisions that affect integrated and nonintegrated oil companies differently. We have provided a detailed analysis of these provisions in an appendix to my statement.

In my testimony this morning, I would like to discuss some of the broad energy and tax questions that are raised by the policy of taxing integrated major oil companies and nonintegrated independents differently. My testimony will cover: first, the tax code provisions that distinguish between independent and integrated producers; second, the relationship between these provisions and energy and tax policy goals; and third, the revenue effects of changing these provisions.

## STRUCTURE OF THE INDUSTRY

A broad spectrum of firms are engaged in the oil and gas industry, ranging in size from Exxon, with $63 billion in assets, to the small stripper operator in Texas. For purposes of the tax code, firms are often taxed differently depending on whether or not they qualify for independent producer status. The code defines an independent company as a producer that does not have annual retail sales of more than $5 million nor refine more than 50,000 barrels on any single day during the year. Producers that do not qualify for this status are typically referred to as the major or integrated companies.

In general, the major oil companies are the largest firms in the industry and are extensively engaged in refining and marketing, as well as in other lines of business. In addition, most of the majors have large foreign oil and gas operations. Table 1 provides information on 240 publicly held oil and gas companies, ranked by their level of production. Very few of the 50 largest companies qualify for independent status under the tax code, although many of them are classified as independents under looser and more general industry standards.

[The table follows:]

TABLE 1.—DISTRIBUTION OF PUBLICLY HELD CORPORATIONS, BY SIZE OF PRODUCTION

[Dollars in millions]

| Daily production [1] | Number of companies | Median daily production [1] | Median net assets | Median total revenue |
|---|---|---|---|---|
| 0 to 100 | 28 | 43 | $8.7 | $1.2 |
| 100 to 500 | 41 | 247 | 17.2 | 3.6 |
| 500 to 1,000 | 18 | 706 | 31.0 | 20.1 |
| 1,000 to 2,000 | 18 | 1,485 | 88.1 | 26.5 |
| 2,000 to 5,000 | 27 | 3,384 | 130.5 | 78.0 |
| 5,000 to 10,000 | 26 | 6,323 | 246.0 | 98.4 |
| 10,000 to 20,000 | 24 | 15,409 | 858.0 | 809.1 |
| 20,000 to 30,000 | 11 | 23,123 | 708.5 | 712.0 |
| 30,000 to 50,000 | 9 | 40,249 | 1,541.3 | 973.1 |
| 50,000 to 75,000 | 11 | 61,310 | 2,850.7 | 2,738.2 |
| 75,000 to 100,000 | 4 | 89,951 | 2,178.0 | 1,956.9 |
| 100,000 to 500,000 | 11 | 264,800 | 6,048.5 | 9,443.6 |
| 500,000 to 1,000,000 | 6 | 685,816 | 13,701.1 | 16,747.5 |
| 1,000,000 and above | 6 | 3,384,249 | 25,584.5 | 52,953.0 |

[1] Barrels per day. Production of natural gas is converted into barrels of oil at the conversion rate of 6,000 cubic feet per barrel. Production is on a net worldwide basis.

Source: 1983 U.S.A. Oil Industry Directory (Penn Well Publishing Company, 1983)

Ms. RIVLIN. The independents are a very diverse group of firms and range in size from small proprietorships to corporations with over $1 billion in assets. Most publicly held corporations other than the 50 largest producers qualify as independents under the tax code, as do many private corporations, sole proprietorships, and partnerships. Although a number of the larger independents produce more than 1,000 barrels per day, most produce much smaller amounts. As a rule, these companies are almost exclusively engaged in the exploration and production phases of the industry in the United States.

Individual taxpayers who receive royalty payments from oil and gas companies may also qualify as independent producers for tax purposes, although their role is generally limited to ownership of the mineral rights to oil and gas reserves.

### DISTINCTIONS IN THE CURRENT TAX LAW

The first statutory distinction between major and independent oil companies was made in 1975 when the Congress repealed the percentage depletion allowance for the majors—until then both majors and independents had been treated the same for tax purposes. Since 1975, the Congress has raised oil industry taxes in a number of ways and has tended to focus the burden more heavily on the major oil companies.

Some of the important tax provisions that currently affect oil producers differently are:

First, an independent producer, including royalty recipients, may claim percentage depletion on up to 1,000 barrels per day or an equivalent amount of natural gas. Although many of the large independents produce more than 1,000 barrels per day, they are only allowed percentage depletion on their first 1,000 barrels per day. Thus this provision is relatively more important to the smaller independents that are allowed percentage depletion on their full production.

Second, the Windfall Profit Tax Act of 1980 established lower tax rates on the first 1,000 barrels per day on most types of oil produced by the independents. Oil from new fields, however, is taxed the same for all firms.

Third, the Economic Recovery Tax Act of 1981 exempted independent stripper production—that is, oil from wells that produce less than 10 barrels per day—from the windfall profit tax.

Fourth, the Omnibus Reconciliation Act of 1980 provided for a $1,000 tax credit against windfall profit tax liabilities for royalty recipients. ERTA changed the credit to a two-barrels-per-day exemption in 1982, rising to three barrels per day in 1985. Royalty recipients, however, are not allowed reduced windfall profit tax rates or the stripper exemption.

Finally, the Tax Equity and Fiscal Responsibility Act of 1982 required the majors to amortize 15 percent of their intangible drilling costs over 3 years, rather than writing them all off right away as prior law permitted. Intangible drilling costs are capital expenditures with no salvage value, such as amounts paid for fuel, labor materials, and supplies used in the preparation or drilling of oil or gas wells. Independents were allowed to continue writing off all of these costs in the first year.

These provisions and others that provide different treatment for majors and independents are described in more detail in the study appended to my statement.

CBO has estimated the effect of several of these provisions on three oil properties, depending on whether the producer is an independent or an integrated company. Table 2 sets out the present value of future tax payments for each property and three different producers.

[The table follows:]

## Table 2.—ESTIMATED PRESENT VALUE OF TAXES FOR THREE OIL WELLS

[In thousands of dollars, except as otherwise noted]

| Type of producer | Well No. 1 | Well No. 2 | Well No. 3 |
|---|---|---|---|
| Integrated corporation: | | | |
| Corporate income tax | $2,125.3 | $127.8 | $335.5 |
| Add-on minimum tax | 0 | 0 | 0 |
| Windfall profit tax | 200.9 | 140.7 | 602.5 |
| Personal income tax | 1,695.0 | 122.2 | 323.9 |
| Total taxes | 4,021.3 | 390.7 | 1,261.8 |
| Tax per barrel (dollars) | 8.25 | 7.71 | 10.40 |
| Tax rate [1] (percent) | 56 | 61 | 67 |
| Independent corporation: | | | |
| Corporate income tax | 1,760.4 | 98.1 | 261.9 |
| Add-on minimum tax | 64.1 | 11.3 | 30.2 |
| Windfall profit tax | 200.9 | 79.9 | 430.3 |
| Personal income tax | 1,782.3 | 145.2 | 386.4 |
| Total taxes | 3,808.7 | 334.4 | 1,108.8 |
| Tax per barrel (dollars) | 7.81 | 6.61 | 9.14 |
| Tax rate [1] (percent) | 53 | 54 | 61 |
| Sole proprietorship or partnership: | | | |
| Corporate income tax | 0 | 0 | 0 |
| Add-on minimum tax | 0 | 0 | 0 |
| Windfall profit tax | 200.9 | 79.9 | 430.3 |
| Personal income tax | 1,802.6 | 106.9 | 285.1 |
| Total taxes | 2,003.5 | 186.8 | 715.4 |
| Tax per barrel (dollars) | 4.10 | 3.69 | 5.90 |
| Tax rate [1] (percent) | 31 | 33 | 44 |
| Property characteristics: | | | |
| Peak production (barrels per day) | 200 | 15 | 50 |
| Initial reserves (barrels) | 487.539 | 50,622 | 121,262 |
| Oil tier classification | 3 | 1–2 | 1 |
| Drilling investment (producing well) | 750 | 250 | 400 |
| Drilling investment (dry well(s)) | 2,100 | 0 | 300 |
| Depreciable equipment | 160 | 40 | 60 |
| Inflation rate (percent) | 5 | 5 | 5 |
| Discount rate (or hurdle rate) (percent) | 12.5 | 12.5 | 12.5 |

[1] The tax rate is the percentage difference between the pretax and post-tax rate of return on the total investment, based on a corporate tax rate of 46 percent and a personal tax rate of 50 percent.

Note.—For further details on the methods used to calculate these tax payments, see Appendix, Part III.

**Ms. Rivlin.** Well No. 1 is a well in a new field. Well No. 2 is a well in an existing field that becomes a stripper after 5 years. Well No. 3 is a well in an existing field.

The present value of the tax payments reflects the total taxes—corporate, personal, and windfall—that an investor can expect to pay over the life of an investment, discounted for the fact that future payments have a lower current value than more immediate ones.

As the table shows, the independent corporation pays significantly lower taxes than the integrated company. On a per barrel basis, the integrated firm would pay 44 cents more per barrel in tax on oil from well No. 1; $1.10 more on oil from the stripper well; and $1.26 more on oil from well No. 3. These differences are equivalent to price subsidies for oil produced by an independent. The lowest price subsidy is for new oil because the windfall profit tax rate is the same for both types of firms.

The biggest difference in tax treatment, however, is between corporations and sole proprietorships or partnerships. Investors in corporations pay a substantial corporate income tax for the privileges of that form of legal organization. In the hypothetical cases shown in table 2, the tax on a barrel of new oil produced by a corporate firm is more than $3 higher than that on a barrel produced by a noncorporate firm. Because almost all partnerships or sole proprietorships in the oil and gas industry are independents, the special provisions for independents enlarge the tax differential between integrated corporations and noncorporate firms.

### EVALUATION OF SPECIAL TAX TREATMENT FOR INDEPENDENTS

Although the special tax treatment of independents is a departure from the normal tax policy standards of fairness and efficiency, it has been justified by its proponents for other reasons: Encouraging competition in the oil industry, for example, or stimulating domestic oil production.

The first tax policy issue is fairness. Currently, corporations produce most oil and gas. Both integrated and independent corporations are subject to the corporate income tax, and their dividends, or capital gains, are subject to the personal income tax. On grounds of fairness or equity, there does not appear to be a sound argument for taxing one corporation differently from another equally profitable corporation in the same industry. Similarly, there is no apparent justification for taxing one set of investors differently from another simply because one set invests in a company that does not own refining or retailing operations.

The second tax policy issue is efficiency. Artificial distinctions among different producers are generally not consistent with economic efficiency. When considering an investment in a domestic onshore oil property, the integrated and the independent are not competing on an equal footing. As indicated by the per-barrel tax differentials, for example, the independent can afford to devote more resources to a property because of lower windfall tax rates or percentage depletion. Thus, even though an integrated firm might be more able to produce at lower real cost, the independent can pay more for the property, or charge lower prices, simply because of the tax benefits. Neutral tax treatment would help insure that the most efficient producers remain in business, while the less efficient ones are weeded out. To the extent that differential tax treatment diverts capital to less efficient producers, it is not consistent with the most effective use of our Nation's resources.

### RATIONALES FOR DIFFERENTIAL TAXATION

Although differential taxation may not be consistent with tax policy concerns, there may be other justifications for it. One set of arguments made on behalf of special tax treatment for independents both in 1975 and more recently turns on the special difficulties of independents in obtaining financing, and on the advantages of encouraging competition in the oil industry.

Access to capital. It is argued that the independents have a harder time raising capital than the major companies. Because they are not diversified, the earnings of the independents are subject to greater variation. In general, the independents have higher debt/equity ratios than the majors; this exacerbates the variation in their rates of return on equity. Thus, it is said that banks tend to consider the independents to be more risky and may restrict credit or charge them higher interest rates.

In addition, private individuals must be willing to accept a higher degree of risk when considering investing in an independent. According to this view, preferential tax treatment not only allows the independents to increase their case flow, but it makes them more attractive to private investors. By somewhat reducing the risk associated with an independent producer, special tax treatment allows the independents to generate more capital than they would otherwise.

Low profits. Another argument for differential taxation is that the independents are smaller than the integrated firms and do not earn the same level of profits. The independents cannot rely on other operations—that is, refining or retailing—to maintain their cash flow when the extraction business is depressed. This is held to be particularly important because the high level of fixed interest payments makes the independent very susceptible to bankruptcy during cyclical downturns.

Competition. Proponents of preferential tax treatment for the independents also hold that it allows them to compete more effectively against the integrated companies, thereby limiting the control the major companies can exert over the oil market. Thus, the tax code can work as a supplement to the antitrust laws by restricting the market power of the larger companies.

These arguments for providing favorable tax treatment to a subset of firms in the oil industry are based largely on firm size: Small firms make lower profits, have less access to national capital markets, and have smaller market shares.

These arguments, however, could be made for any sector of U.S. industry. For the independents in the petroleum industry, the allowance of special tax preferences extends privileges not accorded small businesses in other industries. On the other hand, the oil industry is riskier than other sectors and tax incentives help reduce the high risks that an independent must face.

Special tax treatment for the independents has also been justified as a way of promoting domestic oil and gas production. Because most of their exploration and drilling activity is in domestic onshore fields, preferential tax treatment for independents represents an investment in more secure and reliable energy production.

Furthermore, it is argued that the independents will operate wells and fields that a major oil company would no longer consider economic, thus gaining production from fields that have already been developed. The independent exemption for stripper oil under the windfall profit tax, for example, allows independents to maintain domestic stripper wells that might otherwise be abandoned if their production were subject to the tax. Similarly, the allowance for percentage depletion reduces the cost to the independents of investing in domestic exploration and production activites.

In general, any provision that reduces the tax burden on an oil and gas investment will marginally increase domestic exploration and production.

Although the special independent tax provisions are consistent with the purpose of increasing U.S. production, they could be designed in a more uniform fashion; both integrated and independent producers could be provided the same incentives. For example, if the stripper exemption prevents the premature abandonment of wells, both independents and integrated producers could be exempted. More uniform incentives would increase domestic production by the majors, as well as by the independents.

An even more direct way of increasing domestic production, however, would be the imposition of an oil import fee. This would increase the profitability of domestic operations of both the majors and the independents alike. In addition, it would encourage energy conservation and the production of other domestic fuels, such as coal or natural gas.

### REVENUE ESTIMATES FROM CHANGING TAX PROVISIONS

Significant revenues could be raised over the 1984–88 period by making tax provisions consistent for all oil and gas firms. Table 3 sets forth CBO's revenue projections from various changes in the tax law that would move toward uniformity of treatment for different producers.

[The table follows:]

TABLE 3.—ESTIMATED REVENUE EFFECTS OF CHANGING TAX PROVISONS FOR OIL AND GAS PRODUCERS

[In fiscal years and billions of dollars]

| Option | 1984 | 1985 | 1986 | 1987 | 1988 | Cumulative 5-year Increase |
|---|---|---|---|---|---|---|
| Capitalize all IDCs | $2.1 | $3.6 | $3.3 | $3.2 | $3.1 | $15.3 |
| Amortize 15 percent of IDCs over 3 years | 0.1 | 0.1 | 0.1 | ([1]) | ([1]) | 0.4 |
| Eliminate stripper exemption for windfall profits tax (retain reduced tax rate) | 0.2 | 0.2 | 0.2 | 0.2 | 0 2 | 1.1 |
| Eliminate all reduced windfall profit tax rates for independents (no stripper exemption) | 0.5 | 0.6 | 0.5 | 0.5 | 0.5 | 2.6 |
| Repeal percentage depletion | 0.9 | 1.7 | 1.9 | 2.0 | 2.2 | 8.7 |
| Repeal exemption for royalty holders | 0.4 | 0.5 | 0.4 | 0.4 | 0.4 | 2.0 |
| Expense all IDCs | −0.2 | −0.2 | −0.1 | −0.1 | −0.1 | −0.6 |
| Extend stripper exemption to all producers | −0.7 | −0.9 | −0.9 | −0.9 | −0.9 | −4.3 |
| Impose oil import fee, $2 per barrel | 3.1 | 4.4 | 4.3 | 4.3 | 4.3 | 20.4 |

[1] Less than $50 million.

Sources: Joint Committee on Taxation and Congressional Budget Office

Ms. RIVLIN. Two options are presented for intangible drilling costs—IDCs. The first option—capitalization of all intangible drilling costs associated with producing wells—would apply to both independents and integrated companies. This would require firms to amortize their drilling costs over the productive life of the well, rather than expensing them all—or 85 percent in the case of majors—in the first year. These costs would be added to the depletable basis of the property and recovered through cost depletion. Currently, this is the generally accepted practice that firms use for financial—as opposed to tax—reporting. This option would raise $15.3 billion over the 1984–88 period. Note that number is slightly different from one that appears in the appendix, because we got a more recent estimate.

A second intangible drilling cost option would affect only independent companies—it would require them to amortize 15 percent of their intangible drilling costs over 3 years, as is currently required of integrated companies. This alternative would raise $0.4 billion over the 1984-88 period.

The option to repeal percentage depletion also would affect only the independent firms and would raise $8.7 billion over the 1984-88 period. Under this alternative, firms would be required to use the cost depletion methods that the integrated companies are currently required to use. In general, the independent companies already use cost depletion for financial reporting purposes so that they can report higher earnings to their shareholders.

One option for making the windfall profit tax more uniform is the repeal of both the stripper exemption and the reduced rates for independents. Under this option, all oil would be taxed at the same set of rates for independent and integrated producers. Royalty interests currently exempt—such as those owned by State and local governments, Indian tribes, or charitable institutions—would remain untaxed. These changes would increase revenues by $2.6 billion over the 5-year period.

A second alternative for improving the uniformity of the windfall profit tax is to extend the current stripper oil exemption to the major oil companies. This would reduce revenues by $4.3 billion over the 1984-88 period. As a result, the windfall profit tax would not impose an incentive on any firm to abandan stripper wells that might still be economically productive.

Finally, CBO has estimated that a $2-per-barrel oil import fee would raise $20.4 billion over the 1984-88 period. A fee on imported oil would heighten conservation incentives by pushing up the price of all foreign and domestically produced oil. In addition, because the fee would allow domestic energy prices to rise, it would provide a subsidy for all substitutes for imported oil, including domestic oil. Thus, an import fee could be combined with elimination or reduction of some of the existing, more direct, subsidies to oil producers, such as percentage depletion or the deduction for intangible drilling costs.

To illustrate the effects of changes such as these on individual properties, the Congressional Budget Office has estimated the effects of repealing percentage depletion and capitalizing intangible drilling costs for producing wells on a discounted present value basis.

The results for the hypothetical new oil well discussed earlier are shown in table 4.

[The table follows:]

### Table 4.—PRESENT VALUES OF TAXES FROM REPEALING PERCENTAGE DEPLETION AND CAPITALIZING INTANGIBLE DRILLING COSTS

[In thousands of dollars, except as otherwise noted]

| Type of producer | With cost depletion | With capitalized intangible drilling costs [1] | With cost depletion and capitalized intangible drilling costs [1] |
|---|---|---|---|
| Integrated corporation: | | | |
| Corporate income tax | $2,125.3 | $2,310.0 | $2,310.0 |
| Add-on minimum tax | 0 | 0 | 0 |
| Windfall profit tax | 200.9 | 200.9 | 200.9 |
| Personal income tax | 1,695.0 | 1,641.5 | 1,641.5 |
| Total taxes | 4,021.3 | 4,152.3 | 4,152.4 |
| Percent change in taxes [2] | 0 | +3 | +3 |
| Tax per barrel (dollars) | 8.25 | 8.52 | 8.52 |
| New tax rate (percent) | 56 | 57 | 57 |
| Independent corporation: | | | |
| Corporate income tax | 2,117.5 | 2,085.1 | 2,310.0 |
| Add-on minimum tax | 0 | 32.8 | 0 |
| Windfall profit tax | 200.9 | 200.9 | 200.9 |
| Personal income tax | 1,697.3 | 1,697.2 | 1,641.5 |
| Total taxes | 4,015–7 | 4,016.0 | 4,152.4 |
| Percent change in taxes [2] | +5 | +5 | +9 |
| Tax per barrel (dollars) | 8.23 | 8.24 | 8.52 |
| New tax rate (percent) | 56 | 56 | 57 |
| Sole proprietorship or partnership: | | | |
| Corporate income tax | 0 | 0 | 0 |
| Add-on minimum tax | 0 | 0 | 0 |
| Windfall profit tax | 200.9 | 200.9 | 200.9 |
| Personal income tax | 1,840.3 | 2,052.2 | 2,072.7 |
| Total taxes | 2,041.2 | 2,253.0 | 2,272.6 |
| Percent change in taxes [2] | +2 | +12 | +13 |
| Tax per barrel (dollars) | 4.19 | 4.62 | 4.66 |
| New tax rate (percent) | 32 | 35 | 35 |

[1] Only drilling costs for producing wells are capitalized; dry hole costs are expensed.
[2] Change in tax payments from payments under current tax law. See Table 2, Well No. 1.

Ms. RIVLIN. Both changes in the tax law would have different effects on different types of oil producers. Because the majors are not currently entitled to percentage depletion, they would have the smallest change in their tax payments. The combination of both changes would raise the present value of taxes by 3 percent for the integrated company and 9 percent for the independent corporation.

## CONCLUSION

In conclusion, in general, greater uniformity in the taxation of oil and gas producers would further the policy goals of economic efficiency and tax fairness, and could encourage domestic energy production. Smaller independents might, however, have more difficulty obtaining financing and competing with larger producers. Movement toward tax uniformity could also raise substantial revenue and help reduce the size of projected long-term budget deficits.

Thank you, Mr. Chairman.

[A prepared study follows:]

# ANALYSIS OF SPECIAL TAX PROVISIONS AFFECTING INDEPENDENT OIL AND GAS PRODUCERS

Special Study

Prepared at the Request of
Subcommittee on Oversight
Committee on Ways and Means
U.S. House of Representatives

May 1983

Congressional Budget Office
Congress of the United States

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This study was prepared by Robert Lucke of the Tax Analysis Division of the Congressional Budget Office, under the supervision of James M. Verdier. Questions regarding the analysis may be addressed to them at 226-2680.

## PART I. DESCRIPTION OF THE INDEPENDENTS

A broad spectrum of firms are engaged in petroleum exploration and production in the United States. The companies range in size from Exxon ($62.9 billion in assets) to Patton Oil ($6.2 million in assets) to the lone stripper operator in Oklahoma. From the standpoint of the actors in the petroleum business, there are two types of firms in the industry--the large integrated producers (the majors) and the independents (all the rest). Whereas the integrated companies are involved in exploration, production, refining, and marketing, the independent firm frequently restricts its operations to the exploration and production phases of the business. In general, the independents are active in onshore areas and leave the high-cost offshore fields to the majors.

Two definitions of "independent" are used in this paper. One is that used by the petroleum industry, which considers all but the the very largest oil and gas corporations--about 25 firms--to be independent producers. Another definition is that of the tax code, which usually defines an independent as a producer with no significant retail or refining operations, thus excluding refiners, gas distribution companies, service station operators, and fuel oil (residential) distributors. For statistical reasons, the standard industry definition will be used in Part I, which provides an overview of independent operators. In Part II (tax provisions), the tax code definition will be used.

The oil and gas industry includes a wide variety of actors--from large multinational corporations to passive investors. A number of parties usually have an economic interest in any given oil property. Partnerships and joint ventures are common, used both to raise capital and to share risks among producers. Although there may be a number of separate economic interests in a given property, there is usually only one firm that does the actual work. This partner or operator is the actor responsible for actually conducting the exploration, production, and distribution operations (though it may also contract with other firms to perform these activities). The distinction between gross and economic (net) interests is important for both statistical and tax reasons. In general, production statistics on a "gross" basis reflect the activities of a firm or subset of firms regardless of ownership interest (that is, gross production is the amount that a company actually produces). On a gross operator basis, a firm will report data for all properties operated, regardless of ownership; this includes working interests, royalty interests, and production payments to the owners. Statistics derived on a "net" basis reflect the economic interests of a firm or firms. Thus, net company statistics reflect the net ownership of a firm's interests in oil and gas leases. For example, a firm may produce 100 barrels--its gross production--and have an economic (net) interest of only 70 barrels. In addition, firms are generally taxed only on their economic or net interests and not on their gross production.

## Structure of the Industry

In 1981, the independents (all oil and gas companies other than the top 24, ranked by value of production) accounted for 25 percent of the oil and 40 percent of the natural gas produced domestically (see Table 1).[1] The "independents" can basically be divided into two groups--the large and medium-sized corporations that are similar to the majors, and a large number of smaller corporations, proprietorships, and partnerships. Firms other than the top 200--that is, firms other than the majors or the large independents--produced about 10 percent of the oil and 11 percent of the natural gas in the United States. Although production is dominated by the larger firms in the industry, there are a number of small firms competing on the fringe. According to 1977 statistics, approximately 6,230 companies were engaged in oil and gas extraction (and another 7,637 were involved in oil and gas field services).[2]

The producing companies generally do not receive 100 percent of the revenue derived from their operations. In 1981, the top 24 companies produced 75 percent of the oil, but had an economic interest of only 62 percent. Similarly, the top 200 firms produced 90 percent of the oil, but had a net interest of 72 percent. The differences between the gross and the net interests reflect the royalty payments to landowners and interests of limited partners and other investors.

On average, firms other than the top 200 produced about 101 barrels per day (net) of oil and 612 MCF (thousand cubic feet) per day of natural gas.[3] In contrast, firms in the top 200 averaged 30,418 barrels per day of oil and 179,862 MCF per day of natural gas production. Stripper production

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[1] For statistical reasons, the independents are defined as firms other than the top 24, instead of the top 25.

[2] Companies without paid employees are excluded.

[3] Clearly, this assumes that the universe of companies has remained the same as in 1977. If more firms have entered the market, which

TABLE 1. OIL AND GAS INDUSTRY STATISTICS, BY CATEGORY OF COMPANIES RANKED ACCORDING TO VALUE OF PRODUCTION, 1981

| | Total United States | | Top 24 Firms (percent) | Next 176 Firms (percent) | Other Firms (percent) |
|---|---|---|---|---|---|
| Gross lease revenues | 141,222.1 | mil. dol. | 69 | 21 | 10 |
| Net lease revenues | 141,222.1 | mil. dol. | 56 | 14 | 7 |
| Gross oil production | 3,111.8 | mil. bbl. | 75 | 15 | 10 |
| Net oil production | 3,111.8 | mil. bbl. | 62 | 10 | 7 |
| Net stripper production | 438.9 | mil.bbl. | 40 | 10 | 21 |
| Gross natural gas production | 20,251.6 | BCF | 60 | 29 | 11 |
| Net natural gas production | 20,251.6 | BCF | 47 | 13 | 7 |
| Gross exploration expenditures | 16,899.2 | mil. dol. | 40 | 32 | 28 |
| Gross development expenditures | 19,001.7 | mil. dol. | 38 | 33 | 29 |
| Gross number of wells drilled | 68,622 | wells | 20 | 20 | 60 |
| Employment | 215.4 | thousand | 45 | 25 | 30 |
| Gross book asset (net interest, end-of-year) | 196,570.0 | mil. dol. | 67 | 25 | 8 |
| Number of firms[a] | 6,230 | | 24 | 176 | 6,030 |
| Average net oil production (barrels per day per firm) | 1,074 | bbl/day | 219,543 | 4,028 | 101 |
| Average net gas production (MCF per day per firm) | 6,367 | MCF/day | 1,078,664 | 57,298 | 612 |

NOTE: BCF is billion cubic feet and MCF is thousand cubic feet.

SOURCE: U.S. Department of Commerce, Bureau of the Census, Annual Survey of Oil and Gas, 1981, Tables 1, 2, 6A, and 6B; and General Report on Industrial Organization: 1977 Enterprise Statistics, Table 16.

[a] Number of firms is as reported in 1977 Enterprise Statistics. This excludes companies without a payroll.

(oil from wells that produce less than 10 barrels per day) was about 14 percent of total oil production; the top 200 firms produced 50 percent of this amount. Of the 755,848 producing oil and gas wells in 1981, 409,539 (54 percent) were stripper wells.

In general, most oil is produced by firms organized on a corporate basis. In 1981, corporations produced 95 percent of the oil and gas on a gross operator basis. Sole proprietorships were responsible for about 3 percent and partnerships produced about 2 percent. These shares represent gross amounts produced by the firms, even though they may not be entitled to the full economic interest in the production. On a net basis, the producing corporations have an interest of 75 percent as compared to their 95 percent share of gross oil production. Sole proprietorships and partnerships each have a 1.5 percent net interest in oil production. Nonproducers have net interests in oil of about 22 percent and in natural gas of 29 percent. These interests include parties outside the industry, such as individual royalty holders, limited partners, and landowners (for example, governments and non-oil corporations).

## Drilling and Exploration

The independents play a more important part in drilling and exploration than in production. Of the $35.9 billion spent on drilling and equipping exploratory and development wells, 61 percent was spent by firms other than the top 24 companies. Firms other than the top 200 spent 29 percent ($10.3 billion) compared to their 10 percent share of gross lease revenues. Corporations were responsible for 92 percent of drilling expenditures; partnerships and sole proprietorships accounted for a total of 7 percent of expenditures. Corporations also drilled 76 percent of the exploratory and 87 percent of the development wells.

While the large oil and gas corporations spend more for exploration and development wells than the smaller firms, in terms of the number of wells the situation is reversed--firms other than the top 200 drilled 60 percent of the total wells completed during 1981. This indicates that the larger firms drill deeper and more costly wells than the independent firms. The top 200 firms completed wells averaging about 6,700 feet in depth, at $138 per foot; the other firms completed wells averaging about 4,600 feet and costing $54 per foot. In part, this reflects the greater activity of the large companies in offshore areas.

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Footnote Continued

is believed to be the case, the average production figures would be lower.

## Finance

Oil and gas companies are financed in a variety of ways. The larger companies are often publicly held corporations that can raise cash in the security markets. This is also true of the larger independents, such as Superior Oil or Mesa Petroleum. Larger firms also rely heavily on internally generated funds. It is also common for companies to engage in joint ventures, allowing them to spread the risk (and any consequent rewards). To the extent that these joint ventures are between major corporations, they are financed by the sponsoring firms.

Smaller oil and gas companies are generally privately held corporations, partnerships, or sole proprietorships. These firms rely less on public capital markets and more on private investors and banks as sources of finance. As with the large firms, they are also dependent upon their own internally generated cash for a large part of their capital spending.

In general, the established oil and gas firms (whether or not they are independent) have a history of profitability and are thereby able to utilize the full range of tax deductions common to the industry: write-offs for intangible drilling costs, percentage depletion or cost depletion, abandonment losses, accelerated depreciation, and investment credits. Smaller and less profitable firms may be less able to take full and immediate advantage of these tax provisions, since savings are limited by the amount of their tax liability. The current tax rules require firms to defer the recognition of losses for tax purposes, thereby reducing the value of deductions. In order for tax deductions or credits to be useful, firms must generate sufficient income and tax liability to absorb them. Thus, it is common for sole proprietors and partnerships (operating) to rely on outside investors with substantial taxable income who can make use of the "extra" write-offs. Those interested in a small oil and gas firm might include other members of the industry--corporations or individuals with positive taxable income--or "passive" investors--such as high-income individuals or non-affiliated corporations that can make use of the write-offs.

Limited Partnerships. Where outside investors are involved in the oil and gas industry, it is commonly involved on a "limited partnership" basis with a general partner (the actual operator). The general partner can be either a corporation or an unincorporated oil and gas firm. The limited partnership arrangement is attractive to outside investors because their liability is limited to their capital contribution, whereas the general partner is liable for the partnership's liabilities in full. The limited partners also generally have little say in how the partnership allocates its drilling and development funds. In this sense, the limited partnership is similar to a corporation--the stockholders have limited liability and do not usually direct the firm's ongoing operations. Unlike a regular corporation, however, the limited partnership arrangement allows the firm to pass through to the partners their full share of deductions and tax losses.[4]

The tax rules generally allow limited partners to take a proportionately greater share of the start-up deductions in exchange for a lower percentage of the revenues. For example, the limited partners may be allocated 90 to 100 percent of the intangible drilling cost deduction of the operation.[5] One of the advantages of this arrangement is that the limited partners will be able to use the high front-end deductions involved in oil and gas drilling.

The limited partnership financing arrangement has significant advantages over a bank loan. If the operating company borrowed the amount necessary to drill an oil field, it would not be entitled to write off its intangible drilling costs right away unless it had taxable income from other sources. (To the extent that a limited partnership takes out a loan, the partners are restricted from taking a tax loss in excess of the amount they personally are at risk.) Thus, the limited partnership arrangement allows small oil firms to generate capital from outside investors who can use tax deductions that might not otherwise be utilized. In addition, it allows individuals the opportunity to invest in a high-risk operation without becoming active participants in the venture, while the operator is free of the definite repayment obligations associated with a loan.

Limited partnerships provide a significant source of finance for the industry, amounting to several billion dollars over the last few years. In 1980, public partnership "drilling funds" registered with the Securities and Exchange Commission (SEC) raised $1.3 billion.[6] These funds represented about 6 percent of all drilling expenditures in 1980 and 20.6 percent of drilling expenditures by firms other than the top 200. In 1981, capital provided through public drilling funds rose to a record $2.0 billion (6 percent of total drilling expenditures), but fell by 50 percent to $1.1 billion in 1982. Drilling capital is also raised through private placements of limited partnerships that are not registered with the SEC. Although there are no available statistics on the amount supplied through these funds, it has been estimated that the amount provided through privately placed funds may be twice that of SEC-registered funds.

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[4] Under the Subchapter S revisions of 1982, limited partnerships are now very similar to Subchapter S corporations.

[5] "Public Oil and Gas Program Investment Declines in 1982," Investor's Tax Shelter Report, vol. 2, no. 1 (January/February 1983), p. 4.

[6] The Tax Reform Act limited special allocations to those circumstances where they have a "substantial economic effect," that is, where the allocation actually affects the dollar amount of the partners' share of the total partnership income or loss, independent of tax consequences.

A Limited Partnership In Action. A limited partnership in the oil industry often takes the form of a general partner offering "shares" to investors in the partnership. The sponsoring firm may set up many such partnerships, each as a separate entity. The general partner directs all oil exploration and development operations; the limited partners have no control over the operating methods of the general partner.

The most common form of limited drilling partnership in oil and gas is referred to as a "functional allocation" program. In this type of structure, the sharing of costs turns on their tax treatment. Investors pay all "expensed" costs (those that are written off right away), while the sponsor pays all capital costs. Revenues are shared from the start of production. Although this arrangement maximizes the first-year deductions of the investors, it also maximizes their exposure to risk, since they are fully responsible for the costs of dry holes. Moreover, the sponsor's share of capital costs, although not fully deductible in the first year, benefits from depreciation under the Accelerated Cost Recovery System (ACRS) plus the investment tax credit and percentage depletion. Thus, the sponsor loses little (if anything) by sharing costs in this way, and gains significant insulation against the vagaries of the industry. This is in addition to a revenue-sharing arrangement that disproportionately favors the sponsoring firm.

A typical sharing of the costs and revenues of a functional allocation program is shown below:

| | General Partner (percent) | Limited Partner (percent) |
|---|---|---|
| Management Fee | 0 | 100 |
| Sales Commissions | 100 | 0 |
| Capital Costs | | |
| Lease bonuses | 100 | 0 |
| Equipment | 100 | 0 |
| Non-capital Costs | | |
| Intangible drilling | 0 | 100 |
| Lifting Costs | 50 | 50 |
| Administrative Overhead | 50 | 50 |
| Revenue* | 50 | 50 |

In this arrangement, the general partner receives 50 percent of the net operating revenue (gross revenue less lifting costs and overhead) in exchange for providing the capital costs, such as lease bonuses and depreciable equipment. As a percentage of the total investment in a producing well, capital costs might be 25 percent. Basically this type of operation calls for the operator to become financially involved when a well is completed and the lease equipment installed. If a lease is abandoned, the limited partners are responsible for the costs involved in nonproducing acreage; the operator is only engaged in acreage that is productive.

Upon formation of a partnership, the proceeds from the sale of "shares" are applied to the development of oil and gas properties. In this case, it is assumed that the limited partners' investment is applied as follows:

| | Percent |
|---|---|
| Management fee | 6 |
| Administrative overhead | 4 |
| Drilling and equipping wells (Intangible drilling costs) | 90 |

Assume, for example, that the investors put up $555,556, of which 90 percent ($500,000) goes toward drilling an oil well. The 10 percent

($55,556) that goes for overhead and management fees may be amortized over 60 months as reimbursement of the costs of organizing a partnership. (Overhead determined to be in excess of reasonable compensation, or determined to be reimbursement of syndication costs, including sales commissions, would not be deductible.)

The operator leases the rights to 500 acres of land that is unproven. The landowner receives an up-front bonus of $50,000 plus a one-eighth royalty. In the first year, the venture drills and completes its well, expending the full $500,000 in intangible costs. If the well turns out to be dry, the investors are allowed to write off their full investment of $555,556. Assuming they are in the 50 percent tax bracket, their real loss is half of their original investment ($277,778).

If the well strikes oil, the tax implications are much more complex. The limited partners are allowed to write off their full share of intangible drilling costs and overhead in the first year. The management fee is considered a partnership organization cost and is amortized over five years. The income and expense profile of the limited partners is shown in Table 2. The well is assumed to remain productive for nine years, after which time the operating costs exceed revenues. The investors are entitled to 50 percent of the revenues and can deduct 50 percent of the costs. The investors are assumed to be eligible for percentage depletion at a rate of 15 percent. For simplicity, it is assumed that the investors are not subject to the alternative minimum tax, in regard either to intangible drilling costs or to percentage depletion.

In 1984, the gross receipts of the partnership are $400,000 and are reduced by the 12.5 percent royalty to arrive at gross income of $350,000. Both the limited partners and the operator share this amount evenly. The limited partners' share of operating costs is $21,875, yielding a net pretax cash flow of $153,125. This amount is then adjusted to reflect the provisions in the tax code for deriving taxable income. The limited partners are allowed percentage depletion of $26,250 and a deduction of 20 percent of their management fee ($6,667). After these adjustments, taxable income is calculated at $120,208, yielding a tax liability of $60,104. This is subtracted from the investors' pretax cash flow to arrive at their post-tax cash flow of $93,021. This is the amount in which the investor is critically interested when evaluating various investment opportunities.

The general partner's income statement is shown in Table 3. It is assumed that the general partner is a sole proprietor and is subject to a marginal tax rate of 50 percent. The general partner's income share is the same as the limited partners', except that the operator also receives the 6 percent management fee. The general partner invests $75,000 in depreci-

TABLE 2. OIL EXPLORATION PARTNERSHIP - INVESTORS' ACCOUNTS

| | | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | Gross Receipts | 0 | 400,000 | 500,000 | 450,000 | 350,000 | 275,000 | 200,000 | 150,000 | 100,000 | 50,000 |
| | Less royalty | 0 | 50,000 | 62,500 | 56,250 | 43,750 | 34,375 | 25,000 | 18,750 | 12,500 | 6,250 |
| | Gross income | 0 | 350,000 | 437,500 | 393,750 | 306,250 | 240,625 | 175,000 | 131,250 | 87,500 | 43,750 |
| B | Income Allocated to Partners (50 percent) | 0 | 175,000 | 218,750 | 196,875 | 153,125 | 120,313 | 87,500 | 65,625 | 43,750 | 21,875 |
| C | Expenses Allocated to Partners | | | | | | | | | | |
| | Intangible drilling costs (100 percent) | 500,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Administrative and lifting costs (50 percent) | 22,222 | 21,875 | 21,875 | 21,875 | 21,875 | 21,875 | 21,875 | 21,875 | 21,875 | 21,875 |
| | Management fee (100 percent) | 33,334 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| D (B-C) | Pre-Tax Cash Flow | -555,556 | 153,125 | 196,875 | 175,000 | 131,250 | 98,438 | 65,625 | 43,750 | 21,875 | 0 |
| E | Tax Adjustments | | | | | | | | | | |
| | Deduct percentage depletion | 0 | 26,250 | 32,813 | 29,531 | 22,969 | 18,047 | 13,125 | 9,844 | 6,563 | 0 |
| | Amortize management fee | -26,667[a] | 6,667 | 6,667 | 6,667 | 6,667 | 0 | 0 | 0 | 0 | 0 |
| F (D-E) | Taxable Income or Loss (-) | -528,889 | 120,208 | 157,395 | 138,802 | 101,614 | 80,391 | 52,500 | 33,906 | 15,312 | 0 |
| G | Regular Income Tax (50 percent) | -264,445 | 60,104 | 78,698 | 69,401 | 50,807 | 40,196 | 26,250 | 16,953 | 7,656 | 0 |
| H (D-G) | Investor Cash Flow | -291,111 | 93,021 | 118,177 | 105,599 | 80,443 | 58,242 | 39,375 | 26,797 | 14,219 | 0 |

a. The management fee ($33,334) is not allowed as a deduction; this reduces the tax loss by $33,334. However, the investors are allowed to amortize 20 percent of the fee ($6,667) in the first year. Thus, the net effect is to reduce the tax loss by $26,667 ($33,334 - 6,667).

TABLE 3. OIL EXPLORATION PARTNERSHIP - OPERATOR'S ACCOUNT

| | | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | Gross Receipts | 0 | 400,000 | 500,000 | 450,000 | 350,000 | 275,000 | 200,000 | 150,000 | 100,000 | 50,000 |
| | Less royalty | 0 | 50,000 | 62,500 | 56,250 | 43,750 | 34,375 | 25,000 | 18,750 | 12,500 | 6,250 |
| | Gross income | 0 | 350,000 | 437,500 | 393,750 | 306,250 | 240,625 | 175,000 | 131,250 | 87,500 | 43,750 |
| B | Income Allocated to Operator (50 percent) | 0 | 175,000 | 218,750 | 196,875 | 153,125 | 120,313 | 87,500 | 65,625 | 43,750 | 21,875 |
| C | Other Income and Expenses Allocated to Operator | | | | | | | | | | |
| | Plus management fee (100 percent) | 33,334 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Less administration and lifting costs (50 percent) | 22,222 | 21,875 | 21,875 | 21,875 | 21,875 | 21,875 | 21,875 | 21,875 | 21,875 | 21,875 |
| | Less cost of depreciable assets | 75,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Less lease bonus | 50,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| D (B-C) | Pre-Tax Cash Flow | -113,888 | 153,125 | 196,875 | 175,000 | 131,250 | 98,438 | 65,625 | 43,750 | 21,875 | 0 |
| E | Tax Adjustments | | | | | | | | | | |
| | Deduct percentage depletion | 0 | 26,250 | 32,813 | 29,531 | 27,969 | 18,047 | 13,125 | 9,844 | 6,563 | 0 |
| | Depreciation | -64,313[a] | 15,675 | 14,963 | 14,963 | 14,963 | 0 | 0 | 0 | 0 | 0 |
| | Bonus not deductible | -50,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| F (D-E) | Taxable Income | 425 | 111,200 | 149,099 | 130,506 | 93,318 | 80,391 | 52,500 | 33,906 | 15,312 | 0 |
| G | Regular Income Tax (50 percent) | 213 | 55,600 | 74,550 | 65,253 | 46,659 | 40,196 | 26,250 | 16,953 | 7,656 | 0 |
| H | Investment Tax Credit (10 percent) | -7,500 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| J (D-G-H) | Operator Net Cash Flow | -106,601 | 97,525 | 122,326 | 109,747 | 84,591 | 58,242 | 39,375 | 26,797 | 14,219 | 0 |

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a. The cost of depreciable assets ($75,000) is not deductible in the first year; this reduces the tax loss by $75,000. However, the operator is allowed first year depreciation of $10,687, so that the net effect is $64,313 ($75,000 - 10,687).

able assets and $50,000 in the lease bonus in the first year. The bonus is not allowed as a tax deduction--percentage depletion, however, is allowed. The tangible assets are subject to ACRS and the 10 percent investment tax credit. It is assumed that the depreciable property is in the five-year recovery class and is placed in service in the first year.

This type of limited partnership generally favors the sponsoring firm. The general partner has only put up $125,000 to get a 50 percent share of the revenues, while the limited partners have invested $555,556 for the same opportunity. In addition, $75,000 of the operator's investment (depreciable equipment) will be contributed only after the property is known to be productive. The general partner, however, is liable for all debts and obligations that the partnership might generate in excess of the capital contributions of the limited partners.

Although this is only an illustration, it is interesting to note that the internal rate of return for the limited partners (after-tax) is 22.3 percent. In contrast, the internal rate of return on a pretax basis is 16.2 percent. The rate of return is 6.1 percentage points higher after tax than before. This implies that the effective tax rate on the investment is a negative 38 percent. On the general partner's side of the ledger, the post-tax internal rate of return is 94 percent, while the pretax return is 138 percent, yielding a positive tax rate of 32 percent. The reason that these returns are so high is that this is a highly speculative investment that has just happened to pay off. The divergence in returns between the general and limited partners reflects the relative mismatch in revenues and investment between the two parties. Exploratory drilling funds often use the "functional allocation" structure in order to minimize the operator's risk in the venture.

Some limited partnerships engage in a significant amount of borrowing that allows them to leverage their investment. With the adoption of the "at risk" rules in 1976, leveraging can no longer be used to generate a tax loss in excess of the amount for which an investor is personally liable. At present, leveraging a limited partnership increases the amount that the venture stands to lose while simultaneously increasing the potential rate of return on equity. In order for a leveraged investment to pay off, the pretax rate of return must exceed the rate of interest on the loan, otherwise leveraging will lower the rate of return. Because the oil business is risky to begin with, increasing the leverage of the investment magnifies the riskiness of the venture.

For example, suppose the investors in the partnership borrowed 50 percent of their capital contribution. Because they are in the 50 percent tax bracket, the investors are essentially paid back their full capital contribution in the first year. In subsequent years, they would have the same cash flow as before except that they would be able to deduct interest payments and would have to pay back the loan. Clearly, if the program returns more than the interest rate, the investors are well ahead of the game; conversely, if the project does not succeed, the investors have to pay back the loan out of their other income or assets.

The functional allocation structure is one of four basic partnership arrangements used by oil and gas drilling funds. Briefly, the others are structured as follows:

Promoted Interest. In this structure, the general partner pays 10 percent or more of the exploration and drilling costs. The sponsor shares disproportionately in the revenues (for example, 25 percent). There is a strong identity of interest between the investor and the sponsor because the general partner has a significant stake in the success or failure of the program right from the start.

Carried Interest. The investors pay 99 percent of all costs. Revenues are shared disproportionately (usually 85 percent to limited partners); thus, the investors' "carry" the operator's share of the costs. This type of structure minimizes the risk to the general partner as the investors bear almost all of the downside risk should the project fail.

Reversionary Interest. This is similar to the carried interest structure in that the investors pay for most of the costs. In this case, however, the investors may receive 99 percent of the revenues until "payout" (as defined by the partnership agreement). Once a project is "paid-out," the sponsor's share reverts to a substantial interest, such as 25 percent.

In addition to differing in their structure, drilling partnerships also differ in their drilling philosophy in regard to exploratory versus developmental wells. Exploratory wells are riskier and the rewards potentially greater; developmental wells are generally less uncertain. In 1982, about 58 percent of the funds in drilling partnerships went toward programs that emphasized exploratory wells; 26 percent to programs that emphasized development wells; and the remainder to basically balanced programs.[7]

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[7] Arthur King, "Simple Factors Make a Big Difference," Tax Shelter Digest, March 1983, pp. 7-11.

A 1982 study of drilling funds indicates the risks and rewards to the investor of such ventures.[8] The average post-tax expected internal rate of return was 9.9 percent, and 21.2 percent of the funds were expected to return in excess of 20 percent. In contrast, about 25 percent were not expected to break even on an after-tax basis.

Drilling funds are the most speculative in the oil and gas area. Other partnerships, called "income" funds, buy proven reserves in the ground, and thereby eliminate the largest risk in the oil industry. The big uncertainty with these programs is future oil and gas prices and not whether a well will be a "duster." In general, these partnerships purchase working interests in producing properties, with the limited partners bearing the costs of exploiting those interests. An income fund is basically an investment in the future price of oil, with a more stable return than an exploratory drilling program. In 1982, income funds registered with the SEC attracted $1.3 billion in capital.[9]

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[8] Ibid.

[9] "Public Oil and Gas Program Investment Declines in 1982," p. 5.

## PART II. SPECIAL TAX PROVISIONS AFFECTING INDEPENDENT OIL AND GAS PRODUCERS

Federal tax law sometimes differentiates between the integrated oil companies and the independents. This part examines several tax code items that impose differing burdens on particular groups of producers in the oil industry. All of the distinctions that have been made between independent and integrated companies have been enacted since 1975 and exempt independents in whole or in part from oil industry tax increases. Although differences in tax treatment existed before 1975 for corporations, partnerships, and sole proprietorships, only recently have oil producers been distinguished by the type of operations they perform. For tax purposes, an "independent" producer is classified as one engaged almost exclusively in the exploration and extraction phases of the oil business. An independent cannot refine more than 50,000 barrels in any single day during the year nor have annual retail sales in excess of $5 million. This basically excludes all producers with significant downstream operations. Unless otherwise noted, this definition applies to all provisions concerning independent producers in the tax code.

### DEPLETION

Oil and gas firms, as well as firms in other extractive industries, are allowed a deduction to reflect the exhaustion of reserves as they are produced. Depletion allowances are analogous to depreciation provisions for capital assets—both are intended to compensate the taxpayer for the decline in value of assets over time.

Basically, two forms of depletion are available to taxpayers for computing annual depletion allowances—percentage depletion and cost depletion. Percentage depletion allows a firm to deduct a fixed percentage of the gross income from the property, regardless of its actual initial cost or current basis. In contrast, cost depletion allows the firm to deduct a percentage of the historical cost equal to the percentage of recoverable reserves produced in a given year. The cost basis of a property is its historical acquisition cost, which includes lease bonus payments, exploratory costs, and any capital expenditures that are not expensed (such as intangible drilling costs) or that are not subject to depreciation (such as lease equipment). Cost depletion is limited to the original cost basis of the property, while percentage depletion is computed without regard to the basis.

Until 1975, all oil and gas producers were allowed to use either cost or percentage depletion, whichever was greater, for tax purposes. The percentage of gross income allowed as a deduction was 22 percent, although before 1970 it had been 27.5 percent. The 1975 Tax Reduction Act severely restricted the allowance for percentage depletion. It limited the deduction to independent producers (excluding integrated companies) and allowed percentage depletion on only the first 2,000 barrels per day of production (phasing down to 1,000 barrels per day by 1980).[1] In addition, it lowered the depletion rate from 22 to 20 percent in 1981, and phased the rate down to 15 percent in 1984 and thereafter. For the purposes of the act, royalty holders and holders of nonoperating interests were also allowed percentage depletion under the same restrictions as independent producers. In 1983, about 29 percent of the value of oil and gas is estimated to be subject to percentage depletion--independent producers accounting for about 13 percent and royalty holders for 16 percent. The act also disallowed percentage depletion on proven properties that were sold after 1974, except in certain special circumstances. Table 4 presents the percentage depletion rates and relevant restrictions since 1926.

Although percentage depletion allows a company to recover more than the cost basis of the property over its useful life, this does not mean that it is preferable to cost depletion in every year. In any cost recovery system, whether it is depreciation for equipment or depletion for oil and gas properties, the primary element in determining the benefits of certain tax provisions is their timing over an investment's life. In the early years of a well's life cost depletion allowances often exceed percentage depletion. Because independent producers have the choice between percentage and cost depletion, they will commonly choose to use cost depletion in the early years of a well and switch over to percentage depletion in later years when the cost basis has declined sufficiently.

Percentage depletion has an advantage over cost depletion in the out-years of a property because by then the cost basis has been reduced. Moreover, during periods of oil price increases, percentage depletion is highly preferable because the size of the allowance increases with inflation, whereas cost depletion is linked to the historical cost of the property.

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[1] Natural gas produced by independents is also allowed percentage depletion based on a conversion factor of 6,000 cubic feet per barrel of oil. Gas producers are allowed to deduct percentage depletion (22 percent) if it is sold under a fixed contract, in effect on February 1, 1975, that prevents price increases from reflecting the increased income taxes resulting from the repeal of percentage depletion.

TABLE 4. PERCENTAGE DEPLETION RATES ALLOWED FOR INDEPENDENT PRODUCERS

| Year | Percentage of Gross Income (percent) | Quantity Limitation (bbl/day[a]) |
|---|---|---|
| 1926 - 1969[b] | 27.5 | None |
| 1970 - 1974 | 22.0 | None |
| 1975 | 22.0 | 2,000 |
| 1976 | 22.0 | 1,800 |
| 1977 | 22.0 | 1,600 |
| 1978 | 22.0 | 1,400 |
| 1979 | 22.0 | 1,200 |
| 1980 | 22.0 | 1,000 |
| 1981 | 20.0 | 1,000 |
| 1982 | 18.0 | 1,000 |
| 1983 | 16.0 | 1,000 |
| 1984 | 15.0 | 1,000 |
| 1985+ | 15.0 | 1,000 |

SOURCE: Walter J. Mead, Dennis D. Muraoka, and Philip Sorensen, "The Effect of Taxes on the Profitability of U.S. Oil and Gas Production: A Case Study of the OCS Record," National Tax Journal, vol. 35, no. 1 (March 1982), p. 23.

[a] The quantity limitation imposes a limit on the amount of percentage depletion that can be claimed by each eligible company (or taxpayer). Alternatively, percentage depletion can be taken on a limited amount of natural gas production. The depletable gas quantity in cubic feet is the depletable oil quantity multiplied by 6,000.

[b] Integrated companies were also allowed percentage depletion before 1975. An integrated company is defined as one that has more than $5 million in retail sales (on an annual basis) or refines more than 50,000 barrels on any day during the tax year.

Since independents are allowed their choice of depletion methods, they obviously have an advantage over the integrated firms.

Percentage depletion may be more or less generous than expensing (writing off the full cost in the first year).[2] In order to mimic expensing, either the full lease acquisition costs would have to be allowed as a deduction in the first year or firms would have to be allowed an annual depletion deduction equal to the net income related to the depletable assets.[3] Because the ratio of net to gross income varies by property (and age of well), no single percentage depletion rate will yield the same result as expensing for all properties. (The ratio of depletable to total assets involved in production also varies considerably by property.) If the policy goal is to provide expensing, it would be easier and more accurate to allow firms to write off all of their oil and gas investments in the first year rather than to allow percentage depletion. This approach would cause problems only for taxpayers unable to use the full deduction in the first year.

Minimum Tax Considerations. Percentage depletion that exceeds the adjusted cost basis of a property is subject to the add-on minimum tax for corporations and the alternative minimum tax for individuals. The current minimum tax rates are 15 percent for corporations and 20 percent for individuals. Cost depletion is not subject to the minimum tax.

When the adjusted cost basis of a property goes to zero, the full percentage depletion deduction is subject to the alternative minimum tax for individuals (assuming the taxpayer's other tax preferences exceed the exemption amount for the minimum tax). The alternative minimum tax is truly an alternative tax because taxpayers pay the greater of their regular tax or their minimum tax. For a taxpayer subject to the alternative minimum tax, marginal percentage depletion deductions are worthless--in fact, extra deductions would raise the taxpayer's total liability. Thus, the alternative tax changes a $50 tax saving to a $20 liability. Only taxpayers with very large amounts of tax-preferred income will be subject to the alternative tax.

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[2] Expensing provides a good comparison because it implies a zero effective marginal tax rate on the asset. In addition, intangible drilling costs, as well as ACRS three- and five-year property, are essentially subject to expensing. Other building and structure investments are accorded less generous capital recovery than expensing, however.

[3] For example, if 50 percent of an investment in an oil property was capitalized (that is, subject to depletion), a firm would be allowed to deduct 50 percent of the net income from the property (for present purposes, "net income" refers to gross income less production costs and excise taxes, but not depletion). Thus, if net income was 75 percent of gross income, the appropriate percentage depletion rate would be 37.5 percent (50 percent of 75 percent) of gross income.

The corporate add-on minimum tax imposes a 15 percent levy on the excess of percentage depletion over the basis of the property. When the basis has been reduced to zero, the minimum tax imposes an additional tax of $21.90 (per $100 of depletion), thereby reducing the tax benefit of depletion from $46.00 to $24.10, a reduction of 48 percent.[4]

## REDUCED WINDFALL PROFIT TAX RATES FOR INDEPENDENT PRODUCERS

The Crude Oil Windfall Profit Tax Act of 1980 established a federal excise tax on oil production based on an estimate of the windfall profit received by producers as a result of oil price decontrol. The act basically established three categories of oil and set different tax rates for each class. The three oil "tiers" are defined as follows:

> Tier One. All oil except that oil classified as Tier Two or Tier Three.
>
> Tier Two. Stripper oil (that is, oil produced from wells with less than 10 barrels per day of production) and oil produced from the Naval Petroleum Reserve.
>
> Tier Three. Newly discovered oil (production from properties developed after 1978), heavy oil, and incremental tertiary oil.

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[4] The reduction in the tax benefit from depletion resulting from the add-on minimum tax is greater than simply the rate (15 percent) times the preference amount (for example, $100). This effect is a result of the fact that a firm's regular tax liability is deducted from the minimum taxable income. For example, the $100 preference gives rise to a tax saving of $46 in regular tax and a direct minimum tax of $15, for a net saving of $31 ($46 - $15). In addition, the preference has reduced the firm's regular tax by $46, thereby reducing the deduction from minimum taxable income--that is, minimum taxable income goes up by $46 because of the preference. This increment is also taxed at 15 percent, so that the total additional tax is $21.90 ($15.00 + $6.90). Thus, the resulting value of the tax preference is $24.10 ($46.00 - $21.90), and the effective minimum tax rate is 21.9 percent.

The standard tax rates specified by the law are 70 percent (of the windfall profit)[5] on tier one oil, 50 percent on tier two oil, and 30 percent on tier three oil.[6] For oil in either tier one or tier two, the act specified reduced rates for independent oil producers on their first 1,000 barrels of production per day.[7] The reduced rate on tier one oil is 50 percent and on tier two 30 percent; there is no reduced rate on tier three oil. Royalty holders are not eligible for the reduced tax rates. Table 5 sets out the tax rates and production shares for 1981 in each category of oil.

In 1981, 6.5 percent of tier one oil (4.5 percent of all taxable oil) was subject to the lower 50 percent rate for independents. This advantage was equivalent to about $3 per barrel of production. On 1,000 barrels per day of production, this amounted to about $1.1 million per producer on an annual basis. This benefit, however, should decline as long as oil prices remain steady (or increase less than the rate of inflation). Because the windfall profit declines if oil prices rise less than the GNP deflator, the tax differential is smaller when real oil prices are lower. In 1981, tier one oil was approximately 70 percent of domestic production. The total tax advantage for reduced rates (on tier one oil) in that year was roughly $494 million. Because the tax is deductible against the corporate income tax, however, the net benefit is only about $266 million since the lower rate reduces the amount allowable as a deduction, thereby increasing income taxes.[8]

Stripper Exemption. Tier two oil (about 14 percent of domestic production) was also subject to reduced rates for independent producers

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[5] The windfall profit is defined as the difference between the market wellhead price and the 1979 controlled price. For example, the tax on tier one oil equals 70 percent of the market price less the base price; that is, tax = 0.7 (market price - base price). The controlled (or base) price is indexed to reflect changes in the GNP deflator.

[6] The tax rate on newly discovered oil was reduced by the Economic Recovery Tax Act of 1981 to 15 percent over a six-year period. The current rate is 25 percent and will be 15 percent starting in 1986.

[7] As defined by the Windfall Profits Tax Act of 1980, an independent's status is determined on a quarterly basis instead of on an annual basis. Thus, in any quarter an independent cannot refine more than 50,000 barrels on any day nor have retail sales in excess of $1.25 million.

[8] This assumes a marginal tax rate of 46 percent for both individuals and corporations.

TABLE 5 SHARES OF TAXABLE PRODUCTION AND WINDFALL PROFIT TAX LIABILITY BY OIL TIER (1981)[a]

| Oil Tier | Percent of Taxable Oil Production | Percent of Windfall Profits Tax Liability |
|---|---|---|
| Tier One | 70.3 | 82.0 |
| Taxed at 70% | 65.8 | 77.3 |
| Taxed at 50% | 4.5 | 4.6 |
| Tier Two | 13.1 | 11.2 |
| Taxed at 60% | 8.3 | 8.6 |
| Taxed at 30%[b] | 4.8 | 2.6 |
| Tier Three (Taxed at 30%) | 16.6 | 6.8 |
| Newly discovered[c] | 11.3 | 5.2 |
| Incremental tertiary | 0.6 | 0.3 |
| Heavy oil | 4.6 | 1.3 |
| Total | 100.0 | 100.0 |

SOURCE: U.S. Department of the Treasury, Internal Revenue Service, Statistics of Income Bulletin, vol. 2, no. 2 (Fall 1982), p. 44.

a. Taxable production excludes production that is exempt, such as state and local government interests, Indian oil, or charitable interests.

b. Production in this class is basically stripper production, which has been made exempt from tax as of January 1, 1983.

c. The newly discovered tax rate is now 25 percent and will decline to 15 percent in 1986 and thereafter.

under the 1980 act. This advantage has been superseded, however, because the Economic Recovery Tax Act of 1981 (ERTA) basically exempted all stripper production by independent companies. In the first quarter of 1982, the average tax per barrel of tier two oil (produced by an integrated company) was $7.80.[9] Because the independent tax rate was half the normal rate, the tax benefit was about $3.90. With the adoption of the stripper exemption, this advantage is now equivalent to the full $7.80. Because the tax is deductible against the income tax the net advantage is about 54 percent of this amount. In addition, the decline in oil prices has also eroded this tax advantage. It is estimated that the current tax differential for independents on stripper oil is now about $6.10 (gross) per barrel (assuming a $30 barrel of oil).

The exemption for stripper oil does not count against a firm's 1,000 barrel limit on oil eligible for reduced rates in either tier one or tier two. (Independents could have some tier two production resulting from the Naval Petroleum Reserve.) A firm could, for example, exempt 700 barrels per day of stripper oil and still receive favorable tax treatment on 1,000 barrels per day of tier one and/or tier two oil.

The exemption of stripper oil was justified in order to prevent "premature abandonment of such properties as the costs of production rise relative to the income available from the property."[10] This exemption will have the effect of extending the economic life (and increasing the ultimate total production) of oil wells that are marginally profitable. That this exemption was only allowed independent producers seems inconsistent with the general intent of the law, however. In 1981, about 40 percent of the output from stripper leases was produced by the top 24 companies (on a net company basis). This indicates that stripper oil production is not solely a province of the independent firm. From the policy standpoint of increasing oil production, there does not appear to be any rationale for eliminating an incentive for independents to cap wells while retaining it for integrated firms.

## WINDFALL TAX EXEMPTION FOR ROYALTY HOLDERS

Current law allows royalty holders an exemption from the windfall profit tax of two barrels of production per day in 1982 through 1984; in

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[9] U.S. Department of the Treasury, Internal Revenue Service, Statistics of Income Bulletin, vol. 2, no. 3 (Winter 1982-83), p. 42.

[10] Joint Committee on Taxation, General Explanation of the Economic Recovery Tax Act of 1981, p. 321.

1985 and thereafter, the exemption will be three barrels per day. When originally passed, the Windfall Profit Tax Act did not include any tax exemption or credit for royalty holders. However, the Omnibus Reconciliation Act of 1980 established a $1,000 tax credit for royalty holders on oil removed in 1980; no provision was made for subsequent years. In ERTA, the Congress extended this credit to $2,500 for 1981 and provided the exemptions that exist under current law for 1982 and thereafter. The rationale for this credit was that the "windfall profit tax on small amounts of royalty income imposed a hardship on many low- and middle-income taxpayers."[11] In 1983, the average tax per barrel is estimated to be about $4.50 (gross) and $2.25 (net), assuming a price of $30.[12] Thus, the two-barrel-per-day exemption currently in effect is equivalent to about a $1,640 credit for the taxpayer facing a 50 percent marginal tax rate, which is less than the $2,500 credit allowed in 1981. (For the taxpayer in the 30 percent tax bracket, the equivalent credit is $2,300.) If the three-barrel-per-day exemption were effective in 1983, it would result in an equivalent credit of about $2,460 for the taxpayer in the 50 percent bracket, and $3,450 for the taxpayer in the 30 percent bracket.

Although the exemption helps low- to moderate-income royalty holders, it also provides a tax break for the high-income taxpayer. In 1980, 57 percent of the net royalty income (from all sources, not only from oil and gas) was reported on returns filed by taxpayers with an adjusted gross income (AGI) in excess of $50,000.[13] Twenty percent of the returns reporting any royalty income had adjusted gross incomes in excess of $50,000. The two-barrel-per-day exemption implies that the royalty holder may be receiving (gross) royalty income of $21,900 annually (at a $30.00 price per barrel) free from the windfall profit tax. The three-barrel-per-day exemption results in $32,850 tax-free royalty income. (Although these royalties are exempt from the windfall profit tax, they remain subject to the regular personal income tax.) For reference, the average AGI on tax returns in 1980 was about $16,200; the average royalty income (from all sources) for royalty recipients with AGI under $50,000 was $3,184; and for royalty recipients with AGI over $50,000 it was $17,293.

In 1982, about 4 to 5 percent of domestic oil production was subject to the royalty exemption. For the calendar year, the tax saving was approximately $856 million (gross); on a net basis the saving was about $498 million. The net saving is less than the gross because lower windfall profit taxes results in a lower deduction (for taxes) and higher personal income taxes.

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[11] Ibid.,

[12] The net is lower than the gross because the windfall profits tax is deductible against the personal income tax.

[13] Net royalty income is gross royalties less depletion and other related costs.

## INTANGIBLE DRILLING COSTS

Until the Tax Equity and Fiscal Responsibility Act of 1981 (TEFRA), both independent and integrated oil producers were allowed to expense their expenditures for intangible drilling costs. These are capital expenditures with no salvage value, such as amounts paid for fuel, labor, materials, and supplies used in the preparation and drilling of oil or gas wells. They exclude expenditures for lease equipment, such as storage tanks or pumping machinery, which would be handled as five-year recovery property under ACRS. Although lease equipment is eligible for the investment tax credit, intangible drilling costs (IDCs) that are expensed do not qualify for the credit. The combination of accelerated depreciation and the investment tax credit is about equivalent to expensing at a 10 percent discount rate; thus, lease equipment and expensed IDCs currently receive similar effective tax treatment.

In TEFRA, the Congress reduced (to 85 percent) the percentage of IDCs that integrated oil corporations could expense; the independent companies may still deduct 100 percent of their IDCs. The remaining 15 percent of an integrated firm's IDCs are amortized on a straight-line basis over three years. In present value terms, this provision reduced the value of deduction for IDCs from 100 percent to about 97 percent (using a discount rate of 10 percent). This provision only applies to producing properties--intangible costs associated with dry holes will continue to receive full expensing treatment.

Minimum Tax Considerations. While the TEFRA provisions directly scaled back the deductions for IDCs for integrated firms, the minimum tax on individuals reduces the value of these deductions for limited partnerships and Subchapter S corporations. Before TEFRA, the individual minimum tax (and the corporate minimum tax for Subchapter S firms) required individuals to include intangible drilling costs in their minimum tax base.[14] The minimum tax rate was 15 percent, and 10 percent of the

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[14] Intangible drilling costs are included in a taxpayer's minimum tax base to the extent that (1) they exceed the amount that would have been deducted had they been amortized over ten years; and (2) that the amount in (1) is greater than a taxpayer's net income from oil and gas properties.

IDC was deductible in the first year. Thus, the minimum tax imposed an effective tax rate of 13.5 percent on the preference, assuming the taxpayer was subject to the tax.[15] For a taxpayer in the 50 percent tax bracket, this provision was equivalent to reducing the preference by 34 percent, to 66 percent of its original value.[16]

Under TEFRA, individuals in partnerships, sole proprietorships, or Subchapter S corporations are subject to a new alternative minimum tax which replaces the minimum tax under prior law. The new minimum tax includes IDCs as a tax preference and the deduction is taxed at a marginal rate of 20 percent (instead of 15 percent as under previous law). The amount of IDCs included in the alternative minimum tax base equals the amount in excess of straight-line amortization over ten years. This is the same definition as under pre-TEFRA law. The alternative minimum tax on IDCs has the same kind of effect as it does on percentage depletion. The marginal IDC deduction ($100) changes from a $50 tax saving under the regular tax (for the taxpayer in the 50 percent bracket) to an $18 liability under the alternative tax. Thus, extra IDC deductions for persons subject to the alternative minimum tax are worthless.[17]

Individuals with limited partnership interests have the option of amortizing their IDCs over ten years (straight-line), and thereby excluding them from the minimum tax base. Taxpayers will find it to their advantage to use the option to capitalize their IDCs if they are subject to the alternative minimum tax. For example, the taxpayer in the 50 percent bracket would reduce the present value of the tax deduction from $50 to

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[15] Under pre-TEFRA law 50 percent of a taxpayer's regular tax was deductible against the taxpayer's minimum taxable income. Thus, the direct minimum tax on IDCs would be $13.50 (per $100 of deduction) and the indirect tax would be $3.75 for a total of $17.25. The indirect tax equals 15 percent of one-half of the reduced liability resulting from the preference. In the case of the taxpayer in the 50 percent bracket, $3.75 = (0.15)(0.5)(0.5)($100).

[16] The taxpayer could have capitalized intangible drilling costs and recovered them through cost depletion, thereby avoiding the minimum tax. However, this was probably not a profitable strategy since future deductions are worth considerably less than current deductions (on a present value basis).

[17] This assumes that the full amount of the "excess" IDCs are included in the minimum tax base. To the extent that income from other oil and gas properties is used to reduce the excess IDCs, the reduction in the value of the preference will be less.

$32.25 by amortizing it over ten years (assuming a 10 percent discount rate). This reduction, however, is clearly preferable to the alternative of an $18 liability to the IRS.

TEFRA also included a second option for taxpayers who are operators (for example, general partners or sole proprietors) of oil and gas properties. These individuals are permitted to treat IDCs as five-year recovery property under ACRS, and thereby exclude IDCs from their minimum tax base. Under ACRS, the taxpayer is entitled to accelerated depreciation plus the 10 percent investment credit (subject to the 50 percent basis adjustment). At a 10 percent discount rate, this option for IDCs is about equivalent to expensing; at a lower discount rate, it is more generous than expensing. Thus, the alternative minimum tax can be completely escaped (at no cost) by taxpayers who are operators of oil and gas properties. Because the ACRS option was not available under prior law, TEFRA actually reduced the minimum tax burden on taxpayers with an active interest in oil and/or gas production.

The current treatment of IDCs for different types of taxpayers is summarized in Table 6.

## AT-RISK RULES

The Tax Reform Act of 1976 placed a limitation on the tax loss associated with an oil and/or gas investment that a taxpayer could deduct; the tax loss cannot exceed the amount the partner is personally liable for. This provision was necessitated by the prevalence of limited partnerships where the partners' personal liabilities are limited to their capital contributions. For example, a partnership may incur a debt for which the partners are not personally liable if the loan cannot be repaid. To the extent that loans were used to drill wells, the intangible drilling costs allocated to the partners could thus have exceeded their capital investment. Limited partners were thereby able to leverage their investment, without facing the concommitant personal liability should the project fail. Under the 1976 tax rules partnerships can still borrow, but the tax losses allowed cannot exceed the capital interest of the partners, unless they are personally liable for these loans. Corporations that invest in limited partnerships are subject to the same at-risk rules as individuals.

In general, sole proprietorships and general partnerships are liable for the full amount of debt they incur, and are allowed to write off the full amount of any tax loss related to their investments. Corporations (both regular and Subchapter S) allow stockholders to limit their personal liability to their capital investment. Corporate stockholders in regular (non-Subchapter S) corporations cannot deduct any more than their capital

### TABLE 6. TAX TREATMENT OF INTANGIBLE DRILLING COSTS

| Type of Taxpayer | Tax Treatment | Present Value of $100 Deduction[a] (dollars) | Present Value of Tax Saving (dollars) |
|---|---|---|---|
| Corporation - Integrated (46 percent tax rate) | First-year expensing of 85 percent of IDCs; the remainder amortized over 3 years (straight-line) | 97.40 | 44.80 |
| Corporation - Independent (46 percent tax rate) | First-year expensing | 100.00 | 46.00 |
| Sole proprietor or general partnership (50 percent tax bracket and subject to alternative minimum tax) | Either<br>(A) First-year expensing subject to minimum tax rules or | -90.00[b] | -18.00 |
| | (B) Treat IDCs as five-year recovery property; no minimum tax | 98.50 | 49.25 |
| Limited partner (50 percent tax bracket and subject to alternative minimum tax) | Either<br>(A) First-year expensing subject to minimum tax rules or | -90.00[b] | -18.00 |
| | (B) Amortize IDCs over 10 years; no minimum tax | 64.50 | 32.25 |
| Individual (50 percent tax bracket and not subject to alternative minimum tax) | First-year expensing | 100.00 | 50.00 |

a. Assumes a 10 percent discount rate and $100 IDC.

b. Assumes taxpayers have no net income from oil and gas properties; the excess IDCs equal the difference between expensing and ten-year amortization. The negative sign implies that there is no tax saving, but an actual tax liability.

investment as a tax loss--this would happen if the corporation's stock price dropped to zero. The corporation structure, even though it provides limited liability to its shareholders, does not allow any tax losses to flow through to stockholders that are in excess of their investment. In contrast, Subchapter S firms both provide limited liability to their shareholders and allow tax losses to "flow through" to the owners, much as under a limited partnership. (The Subchapter S Revision Act of 1982 eliminated the limitations on the extent to which shareholders could utilize percentage depletion deductions.) The Subchapter S rules, however, limit the tax loss that can be claimed by the taxpayers to their capital basis plus any indebtedness of the corporation to the stockholder. Thus, for purposes of the at-risk rules, Subchapter S firms are treated analogously to limited partnerships.

In general, the tax law prevents all individuals from generating tax losses in excess of their capital investment, unless they are personally liable for the debts incurred to generate those losses.

## ACCELERATED WINDFALL PROFITS TAX PAYMENTS

In general, the first purchaser of domestic crude is required to withhold the windfall profit tax amounts payable to the producer and deposit those amounts with the Treasury. The purchaser is liable to the Internal Revenue Service (IRS) for the payment of the amount withheld, as determined by the certification provided by the operator. (This includes any certification of any part of the production eligible for reduced independent tax rates or exemption.) The purchaser files a quarterly return showing the tax withheld and provides each producer with an information statement indicating the amounts of oil purchased and the tax withheld.

The first purchaser must deposit the withheld payments to the IRS within a certain length of time. Major refiners or retailers are required to make semi-monthly estimated deposits of withholding tax. All other purchasers are required to make deposits within 45 days after the end of the month in which the oil was removed from the premises.[18]

The interval between when a tax is withheld and when it is deposited allows a firm to earn interest on the withheld amounts for that interval. On average, the majors are allowed a very brief period (7.5 days) between the time when a tax is withheld and it is due the Treasury. (This assumes that tax is withheld at a constant daily rate over the month.) In contrast the independent purchaser is allowed 60 days (on average) before the withheld tax must be deposited. Thus, on average, the independent purchaser may be able to earn eight times more interest on the withheld tax collections than a major company could. To the extent that the independent operator takes on the deposit obligations of an independent first purchaser, the operator can take advantage of the delayed timing of the liability (the operator and the first purchaser may elect to have the operator assume the purchaser's responsibilities under the tax, Code § 4995(a)(7)(A).) However, if the first purchaser is a major company, the independent operator's payment obligation is the same as for a major company.

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[18] These provisions are described in Joint Committee on Taxation, General Explanation of the Crude Oil Windfall Profit Tax Act of 1980, pp. 57-58.

## REVENUE PROJECTIONS

Significant revenues could be raised over the 1984-1988 period by making the tax provisions consistent for all firms. Table 7 sets forth CBO's revenue projections from various changes in the tax law that would move toward uniformity of treatment for different producers.

Two options are presented for intangible drilling costs. The first option--capitalization of all intangible drilling costs associated with producing wells--would apply to both independents and integrated companies. This would require firms to amortize their drilling costs over the productive life of the well, rather than expensing them all (or 85 percent) in the first year. These costs would be added to the depletable basis of the property and recovered through cost depletion. Currently, this is the generally accepted practice that firms use for financial (as opposed to tax) reporting. The second intangible drilling cost option would only affect independent companies--it would require them to amortize 15 percent of their IDCs over three years as is currently required of integrated companies.

There are also two options for the windfall profit tax. The first would eliminate the current independent exemption for stripper oil, but would leave intact the reduced rate of 30 percent. The second alternative is more sweeping in that both the stripper exemption and the reduced rates on both tier one and tier two oil would be abolished. Under this option, all tier one oil would be taxed at a 70 percent rate and all tier two oil would be taxed at 60 percent. (Interests currently exempt, such as state and local governments, Indian oil, or charitable oil would remain untaxed.) Both these options would only affect production by the independent companies.

The option to repeal percentage depletion would also only affect the independent firms. Under this alternative, firms would be required to use

TABLE 7. ESTIMATED REVENUE EFFECTS OF CHANGING TAX PROVISIONS FOR OIL AND GAS PRODUCERS (By fiscal year, in billions of dollars)

| Option | 1984 | 1985 | 1986 | 1987 | 1988 | Cumulative Five-Year Increase |
|---|---|---|---|---|---|---|
| Capitalize All IDCs | 2.6 | 4.4 | 4.2 | 4.0 | 3.8 | 18.9 |
| Amortize 15 Percent of IDCs over 3 Years | 0.1 | 0.1 | 0.1 | * | * | 0.4 |
| Eliminate Stripper Exemption for Windfall Profits Tax (Retain Reduced Tax Rate) | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 1.1 |
| Eliminate All Reduced Windfall Profit Tax Rates for Independents (No Stripper Exemption) | 0.5 | 0.6 | 0.5 | 0.5 | 0.5 | 2.6 |
| Repeal Percentage Depletion | 0.9 | 1.7 | 1.9 | 2.0 | 2.2 | 8.7 |
| Repeal Exemption for Royalty Holders | 0.4 | 0.5 | 0.4 | 0.4 | 0.4 | 2.0 |
| Expense All IDCs | -0.1 | -0.2 | -0.1 | -0.1 | -0.1 | -0.5 |
| Extend Stripper Exemption to Include All Producers | -0.7 | -0.9 | -0.9 | -0.9 | -0.9 | -4.3 |

SOURCES: Joint Committee on Taxation and Congressional Budget Office.

* Less than $50 million.

the cost depletion methods that the integrated companies are currently required to use. In general, the independent companies already use cost depletion for financial reporting purposes so that they can report higher earnings to their shareholders.

Repeal of the two-barrel-per-day exemption from the windfall profit tax for royalty holders would not directly affect either the independent or the integrated producers, as the exemption does not distinguish oil by type of producer. Instead, it would make the tax treatment of holders of nonoperating royalty interests the same as that of operating interests, who are not currently allowed the exemption. Elimination of the exemption would primarily affect those individuals who are currently royalty recipients.

Lastly, two options are included that would increase consistency, but would reduce revenues. The first option would repeal the 15 percent reduction of the first-year write-off for drilling costs adopted in TEFRA. All firms would be allowed full expensing. The second alternative would extend the stripper exemption to integrated as well as independent firms. Thus, the windfall profit tax would not impose an incentive for any firm to abandon wells that might still be economically productive.

## PART III. METHODOLOGY FOR ESTIMATING PRODUCER TAX BURDENS

One approach to measuring the overall burden of taxation on oil and gas production is to estimate the total taxes a producer is liable to pay over the life of a given property. By discounting the tax payments back to the present, the total "present value" of tax payments can be calculated. This method allows all tax provisions and their timing differences to be taken into account.

The basic framework for this approach involves a "discounted cash-flow" (DCF) model that forecasts the revenues and costs from an oil investment over its life. The investor (producer) discounts the investment's income stream over time in order to calculate the total present value of future income from the project. The investor will purchase the property as long as the owner's asking price is less than or equal to the estimated value of the future net income stream. In the DCF model used here, it is assumed that the investor is willing to pay the landowner an amount (the lease bonus) that is exactly equal to the present value of the future net cash flow.

The discount factor used in the model is 12.5 percent and reflects the minimum anticipated return that the investor will accept after all taxes. If the after-tax return is less than 12.5 percent, the investor will forgo the investment opportunity. Thus, the investor will offer the landowner a bonus that assumes a 12.5 percent post-tax return over the life of the investment.

The DCF model is used to estimate the taxes of three different organizations as follows:

1. Major Integrated Corporation. The investor in a major corporation pays the corporate income tax, the personal tax on dividends, and the capital gains tax on retained earnings. It is assumed that the firm distributes 40 percent of its cash flow and retains 60 percent. The major firm must pay full windfall profits tax rates and must use cost depletion. (The cost depletion basis equals the upfront bonus payment for the property.) Eighty-five percent of intangible drilling costs are written off in the first year, the remainder are amortized over three years.

2. Independent Corporation. Like the investor in the integrated firm, the individual who invests in an independent firm pays the corporate income tax, the personal income tax, and the tax on capital gains. It is assumed that the firm distributes 40 percent of its cash flow and retains 60 percent. The independent corporation pays lower windfall profits rates and is allowed percentage depletion on 1,000 barrels per day of oil production. Because the firm is allowed percentage depletion, it must also pay the add-on minimum tax equal to 15 percent of the excess of percentage depletion over the adjusted cost basis of the property. The firm is allowed to expense all intangible drilling costs.

3. Sole Proprietorship or Partnership. This firm is composed of an individual operator or group of operators (who are not corporations) that all have working interests in the property. This type of organization is advantageous because it avoids the corporate income tax altogether; the individual(s) are subject only to the personal income tax. The firm is allowed reduced windfall profits tax rates, and percentage depletion on the first 1,000 barrels per day of oil production. It is assumed that the owners are not subject to the alternative minimum tax on either percentage depletion or intangible drilling.

In order to provide consistency, it is assumed that the investors in all three firms are in the same tax bracket (50 percent). In addition, it is assumed that all individuals and firms have sufficient taxable income to absorb all the deductions that might arise from an oil investment property. For capital gains purposes, it is assumed that the shareholders hold their stock for four years and then realize their gains. The effective capital gains tax rate under this assumption is 15 percent (instead of the statutory 20 percent), and the overall effective personal tax rate (as a percentage of current cash flow [illegible] percent. In other words, the personal income tax rate is 29 percent for investors in a corporation and 50 percent for investors in a unincorporated enterprise. It is assumed that none of the properties are sold during [illegible] productive lives.

The three hyp[illegible] properties differ in their production profiles and investment characteristics. Table 8 presents the variables for each property. For simplicity, it is assumed that the future price of oil increases at the same annual rate as inflation (5 percent). The wells were chosen so that the production from each well would be treated differently for purposes of the windfall profits tax. Well No. 1 is assumed to produce "new" oil, Well No. 2 is basically a stripper well, and Well No. 3 produces "old" oil.

TABLE 8. ASSUMED VARIABLES FOR DCF MODEL

| | Well No. 1 | Well No. 2 | Well No. 3 |
|---|---|---|---|
| Required Post-Tax Rate of Return (Hurdle Rate) | 12.5 percent | 12.5 percent | 12.5 percent |
| Time of Investment | 1983:1 | 1983:1 | 1983:1 |
| Time of Initial Production | 1983:2 | 1983:2 | 1983:2 |
| Time of Peak Production | 1984:2 | 1984:1 | 1984:2 |
| Time Production Starts to Decline | 1985:1 | 1985:1 | 1986:1 |
| Peak Production Rate (barrels per day) | 200 | 15 | 50 |
| Initial Reserves | 487,539 | 50,622 | 121,262 |
| Production Decline Rate | 15 percent | 10 percent | 17.5 percent |
| Annual Operating Cost | a/ | a/ | a/ |
| Drilling Investment (producing well) | $ 750,000 | $ 250,000 | $ 400,000 |
| Drilling Investment (dry wells) | $ 2,100,000 | 0 | $ 300,000 |
| Lease Equipment Investment | $ 160,000 | $ 40,000 | $ 60,000 |
| Oil Tier | Tier 3 | Tier 1-2 | Tier 1 |
| Windfall Profits Base Price | $ 23.45 | $ 19.84 | $ 16.11 |
| Oil Price Inflation | 5 percent | 5 percent | 5 percent |
| GNP Price Inflation | 5 percent | 5 percent | 5 percent |
| Royalty Rate — to Landowner | 12.5 percent | 12.5 percent | 12.5 percent |
| State Severance Tax Rate | 4.6 percent | 4.6 percent | 4.6 percent |

a. Annual operating cost equals $8,000 plus $60 per barrel of daily production. This amount is adjusted by the GNP price index over time.

The way the DCF model is structured allows the bonus payment to vary to reflect differences in tax treatment. The full amounts of any differences in taxation are assumed to be 100 percent capitalized into the lease bonus. This implies that taxation does not affect oil prices, but that it is manifested in lower payments to the landowners. Thus, higher taxes would mean that the landowners would be paid less, and vice versa.

The DCF model measures only the returns from prospective investments; it does not indicate the returns to past investments. Once the investment becomes a sunk cost, the actual taxes paid over its life will be a function of actual events, not of forecasts or assumptions. In terms of affecting investment behavior on the margin, it is the prospective post-tax returns that determine a firm's investment decisions. The oil production profile used in the DCF model is the expected profile prior to the investment. Ex post evaluations may significantly differ as more information is gained. However, ex post evaluations do not determine initial investment decisions, although they do affect subsequent marginal decisions concerning recovery techniques.

The results from the DCF model are summarized in Table 9. The taxes and tax rates are higher for the corporations than for noncorporate firms because of the corporate income tax. The rates shown here are higher than might be expected, but this analysis is limited to investors in the 50 percent personal tax bracket.

The first well provides an interesting contrast between the integrated and independent corporations. Because it is classified as new oil (tier three), both firms pay the same amount in windfall profit taxes. The integrated firm pays about 20 percent more in corporate taxes because of the requirement for cost depletion and the amortization of 15 percent of its IDCs. This is partially offset because the independent must pay the add-on minimum tax for percentage depletion. In addition, the investors in the independent must pay higher personal taxes because the firm's after-tax cash flow is higher. As a result of these offsetting effects, the overall taxation of the independent is about 5 percent (three percentage points) less than for the integrated company.

The difference in tax rates between the independent corporation and the general partnership indicates the advantage of organizing a firm on a partnership (or Subchapter S) basis. Both firms pay the same windfall profits taxes, but the partnership pays no corporate income tax. As a result, the partnership tax rate is about 20 percentage points lower for all three wells.

The DCF model can be applied to other properties under alternative assumptions. It is not likely, however, that these changes would alter the conclusion that the combination of preferential tax provisions significantly reduces the burden placed on independent oil companies—especially those that are organized on a noncorporate basis.

TABLE 9. ESTIMATED PRESENT VALUE OF TAXES FOR THREE OIL WELLS (In thousands of dollars, except as noted)

| Producer | Well No. 1 | Well No. 2 | Well No. 3 |
|---|---|---|---|
| Integrated Corporation | | | |
| Corporate income tax | 2,125.3 | 127.8 | 335.5 |
| Add-on minimum tax | 0 | 0 | 0 |
| Windfall profits tax | 200.9 | 140.7 | 602.5 |
| Personal income tax | 1,695.0 | 122.2 | 323.9 |
| Total taxes | 4,021.3 | 390.7 | 1,251.8 |
| Tax per barrel (dollars) | 8.25 | 7.71 | 10.40 |
| Tax rate[a] | 56 percent | 61 percent | 67 percent |
| Present value of tax depletion | 534.2 | 3.8 | 16.3 |
| Original depletion basis (lease bonus) | 1,139.9 | 9.2 | 32.9 |
| Independent Corporation | | | |
| Corporate income tax | 1,760.4 | 98.1 | 261.9 |
| Add-on minimum tax | 64.1 | 11.3 | 30.2 |
| Windfall profits tax | 200.9 | 79.9 | 430.3 |
| Personal income tax | 1,782.3 | 145.2 | 386.4 |
| Total taxes | 3,808.7 | 334.4 | 1,108.8 |
| Tax per barrel (dollars) | 7.81 | 6.61 | 9.14 |
| Tax rate[a] | 53 percent | 53 percent | 61 percent |
| Present value of tax depletion | 1,313.1 | 124.5 | 340.7 |
| Original depletion basis (lease bonus) | 1,353.5 | 65.4 | 185.9 |
| Sole Proprietorship or Partnership | | | |
| Corporate income tax | 0 | 0 | 0 |
| Add-on minimum tax | 0 | 0 | 0 |
| Windfall profits tax | 200.9 | 79.9 | 430.3 |
| Personal income tax | 1,802.6 | 106.9 | 285.1 |
| Total taxes | 2,003.5 | 186.8 | 715.4 |
| Tax per barrel (dollars) | 4.10 | 3.69 | 5.90 |
| Tax rate[a] | 31 percent | 33 percent | 44 percent |
| Present value of tax depletion | 1,537.5 | 124.5 | 340.7 |
| Original depletion basis (lease bonus) | 3,157.7 | 213.1 | 579.3 |

[a] The tax rate is the comprehensive marginal tax rate based on a corporate rate of 46 percent and a personal rate of 50 percent. The tax rate is the percentage difference between the pretax and post-tax rate of return on the total investment.

Chairman RANGEL. Thank you, Doctor. And I guess the bottom line is that after reviewing existing tax law, you concluded that there is a fair, more equitable way to encourage competition in this area and to increase domestic oil production.

Ms. RIVLIN. I think so. But it would be at some possible cost to the position of independents.

Chairman RANGEL. Mr. Anthony?

Mr. ANTHONY. Dr. Rivlin, you mentioned the import fee. Yet you did not show what the potential effect of this would be to the consumers, what it may do in regard to an increase in inflation, or any of the other collateral ramifications, other than trying to smooth out some tax policy, treat the different companies more evenly and also raise substantial amounts of revenue.

I wonder if you could address that part of the problem, and also a counterpart. If the Congress moves toward an oil import fee in the future, what would be your position on the domestic fee at the wellhead at the same time?

Ms. RIVLIN. You are quite right in pointing out that an oil import fee does affect prices and ripples through the economy. How serious an effect that is depends, of course, not only on the size of the oil import fee, but on what is happening to the economy.

There was a lot of discussion about an oil import fee during the Carter administration, at a time when inflation was extremely high and oil prices were rising. There was a lot of concern then that an oil import fee would add to the price of energy. At the moment, as oil prices seem to be coming down, and the concern about inflation is less, some of those concerns may be mitigated. But it is still true that, wherever you start, an oil import fee adds to the price of oil and oil products.

If one were to put on an oil import fee, then clearly, as you note, the next question is: Do you extend that, do you make it an excise tax applying to domestic oil or to other forms of energy, as well?

I think that really depends on what you are trying to accomplish.

If the objective is to cut down imports of oil and to encourage domestic production, one would be less inclined to extend the fee to other sources. If the objective is to raise revenue, to treat different sources fairly, and to discourage energy consumption in general, then one would be more likely to extend it more widely.

Ev, do you want to add to that?

Mr. EHRLICH. I would only add that the $2 import fee we discussed would raise the price of refined products by a nickel a gallon.

Mr. ANTHONY. While reading your testimony, you made a statement that the independent exemption for stripper oil under the windfall profit tax allows independents to maintain domestic stripper wells.

I am fairly sensitive to this particular issue, because 99 percent of the State of Arkansas falls in the stripper well classification, even though we do have some oil production.

If I wanted to look at it on a parochial basis, this would be the one area I would have to take a harder look at. Did you take a look at any backup data on the fact that if there was a repeal here, the independents may have difficulty getting bank financing in light of the fact that the oil industry has now suffered some problems since the price has fallen.

We know that a lot of banks across the country, principally some banks in Texas, have had to be taken over, or merge with other banks, because there were a lot of loans outstanding to this very risky industry.

And I think that may prove the point that you made in your statement. I just wonder if you or your staff had developed any corollary between those bank failures and the loans they had outstanding.

Ms. RIVLIN. That is clearly a problem at the moment for much of the oil industry, with the falling price of oil. It is a problem we have noted. Let me see if Bob would like to expand on that.

Mr. LUCKE. We were really not able to do any quantitative work in this area. What we can say is that, by having lower taxes, you increase your cash flow, and, therefore, your risk is probably less, and you are able to pay your debts off easier.

In terms of figuring out how much credit or lack of credit the independents can get, we were not really able to get any data on that.

Mr. ANTHONY. Mr. Chairman, I have one final question. I did not notice anything in your testimony that specifically covered royalty owners. And the royalty owners were covered under the windfall profit tax. I just wondered if you could expand on your testimony, and if you can give any justification for a royalty owner who: (1) Does not participate in the risk, (2) does not put up any money, however takes a percentage because they own the mineral interests and/or the land. Do you believe they should be included in the windfall profit tax.

Ms. RIVLIN. Again, it depends on what you are trying to accomplish—stimulating more production or relieving possible hardships for royalty owners. The royalty owner, as you note, is not participating in the decision about whether or not to go ahead and produce. So, changing the level of tax probably does not change that decision very much.

The concern about royalty owners has been the belief that many of them are little old ladies with low incomes. That may or may not be true, although, I think the facts don't bear that out very strongly. And there may be other ways to protect low-income people than exempting this particular form of income.

Mr. ANTHONY. I think the staff's report shows maybe there was an average income of $40,000 a year by many of the royalty owners.

What bothers me is this: If you were a royalty owner and taxed, and then somebody came and asked you if you could lease another piece of property, would it not make sense that you would add the tax in, or would you find some way in which you could transact business with the people who wanted to do some exploratory drilling on your property? You could either increase the price in some way, or you could try to structure the arrangement so that you could bypass the tax so the net result of the tax would be that you created more cost to the industry. And in return this will filter its way down to the ultimate consumer.

Ms. Rivlin. Well, maybe. But I don't know that my bargaining power would be much affected by whether or not I was taxed, if I owned this piece of land, there was oil on it, and they wanted it.

Chairman Rangel. Mr. Duncan.

Mr. Duncan. What is the economic effect on production from the royalty owners' exemption from the windfall profit tax? I think you said it was 2 barrels this year and maybe 3 next year.

Ms. Rivlin. I think we would expect it to be very small, but I don't know that we can provide you with an exact number.

Mr. Duncan. Could you tell me what effect decontrol and windfall profits tax has had on domestic production?

Ms. Rivlin. Decontrol, even with the windfall profit tax and with the rising price of oil that went along with it, clearly increased domestic production a lot.

Mr. Duncan. I read an article last week that said that some of the small producers, small well owners and royalty owners were suffering or complaining because their income had been reduced because of reduced production on small stripper wells.

Can you comment on that?

Ms. Rivlin. I don't know the particular situation. I think there are a lot of complaints in the oil industry at the moment because the price is not as high as it was. I am not sure that can be blamed on the Congress.

Mr. Duncan. Mr. Chairman, I would like unanimous consent that all members may be permitted to submit questions in writing.

Chairman Rangel. Without objection.

Mr. Pickle. Mr. Chairman, I don't think I have any questions.

It is always good to have Dr. Rivlin here, a very able representative for the Congressional Budget Office, a valuable source of information.

I submit that the analysis you have given this morning is a white paper—giving us a number of choices and options.

I presume that is your intent, as I look at the range.

But I think, if I can just make an observation, while you list a lot of options, I think one you did not list for us is, do you want to kill the independent oil and gas producer of the United States?

From the options you outlined, I submit to you that those would be the death knell of the producers.

I think, as we go further in the next few days, we will find out for the record why we treat independent producers differently.

I thank you.

Chairman Rangel. Mr. Thomas.

Mr. Thomas. Very briefly, in terms of the suggested tax changes that you indicated might be taken, is there any concern about, for want of a better term, I guess I would call a critical mix?

For example, you indicated you might want to extend the windfall profit tax the stripper exemption to corporations and show then a corporation would continue to work a well that produced 2 or 3 barrels or a dozen wells that produced 2 or 3. Isn't there an economic incentive, even though they may have that provision available to them, for a large corporation to expend its manpower and equipment for more efficient production, although that production would be available to them based upon what they have available?

It would be an inefficient use of their resources.

Ms. RIVLIN. It might still be, given their alternative uses of capital. But there would be less disincentive at the margin than there now is to close down the stripper well. That is all.

Mr. THOMAS. Or allow someone else in the business of running stripper wells as a small family operation to maintain those wells in production.

The irony of the situation is in the area I represent. There are a number of, and I won't go into how you want to define a mom and pop operation, because $40,000, if it is an average income, I hear in one committee, isn't very much any more, and we are going to have to do certain things for those kinds of folks because inflation has affected them, but in another committee I hear that $40,000, at least implications are that there is a significant amount of money and these people are not in the category you would assume you thought they were in, widows and so forth.

I just hope we would be consistent in how we treat people in various categories.

My concern is that there are a number of, for example, independent drilling rig companies who are in the business of drilling for oil, whether it be for major corporations or larger or smaller independents. To the degree that you don't have a number of people utilizing their services, they either do not have the rigs or they are sold to other areas or simply sitting there not being used.

It would be a tremendous cost to the large integrated corporations who don't provide a number of facilities—and I am thinking of fishing equipment companies and a number of other supporting industries—if you don't have a number of people available to utilize drilling rigs, they simply would not be there; in many instances costs would go up for companies.

Has any of this been taken into consideration—a critical mix of numbers of people able to utilize various equipment, because obviously oil is not found uniformly. It is in pockets of areas. There are oil economies, and if you have a change in either price or number of people in the business, you have a significant impact on the support facilities. Has that been considered at all?

Ms. RIVLIN. We have not considered that in any detail. We are not in a position really to analyze area by area. But whatever you do about the tax would not change the locus of the oil. It is still there.

Mr. THOMAS. It doesn't change the locus of the oil, but it changes the incentive as to whether or not you either go after it or you stay going after it. There are a number of people who would walk away from a particular well while other people would continue using it.

Has there been any analysis of the impact of suggested tax changes on volume in areas that deal with heavy oil?

Ms. RIVLIN. No. I don't think there has been.

Mr. THOMAS. On pages 6 and 7—I tried to go through the appendix, which is a different document, because on page 7 you referred to the various prices—page 6. You said for further details on the methods used to calculate these see appendix part 3. I could not find, in the brief time I was going through this, any indication of the API gravity that was used on the various wells. For example, either to compute the windfall profit tax or other items.

Ms. **Rivlin**. Let me see if Bob can enlighten you on that, or if we can supply it for the record.

Mr. **Lucke**. We started with an oil price of $30 per barrel.

Mr. **Thomas**. I am sorry. I cannot hear you.

Mr. **Lucke**. We started with an oil price of $30 per barrel.

Mr. **Thomas**. $30 per barrel. Is that realistic or not in today's market?

Mr. **Lucke**. It depends on where it is produced. We assume that it was being produced in Texas, and that it was not heavy oil by any standard.

Mr. **Thomas**. $30 a barrel for Texas oil. What is the average price for Texas oil?

Mr. **Lucke**. It is probably a little lower than that right now, but that was the price at the time the analysis was done.

Mr. **Thomas**. I understand that. For example, in California the average price is around $22, and for heavy oil it goes down to $18 to $25 a barrel.

What was the gravity of the oil on the windfall profit? What tier, for example?

Mr. **Lucke**. We had three different wells. We did not consider heavy oil in any of the three wells. The closest well is well No. 3 which was tier 1 oil.

Mr. **Thomas**. Well 3 was in tier 1 oil?

Mr. **Lucke**. No. I meant to say that well No. 1 was tier 3 oil. We just ran through three examples of wells in this case. The way the computer program is set up now, we can change the variables toward nonspecific examples. If we were, say, to work on some parameters with heavy oil fields in California, we could run through the tax implications of that for you.

Mr. **Thomas**. My concern is that some Texas oil brings a different price than California oil, but certain types of Texas oil don't, certain types of California oil do or don't depending on gravity, location, sulfur content, and a number of factors, as I indicated. In just one county in California, we are talking about better than 160,000 barrels a day.

We would have significant production implications based upon the way in which we altered taxes. Perhaps for the sake of uniformity between individuals in the field, it might be useful as an academic exercise to talk about making taxes uniform, but I want to underscore the comment of the gentleman from Texas, Mr. Pickle, that it also might be a good and worthy national policy to make sure that in creating uniformity for academic purposes, we also don't significantly affect production for either defense or domestic economic consumption.

Thank you, Mr. Chairman.

Ms. **Rivlin** Mr. Thomas, if you wanted us to work through an additional example——

Mr. **Thomas**. Let's do that.

Ms. **Rivlin**. We would be happy to do that.

Mr. **Thomas**. Thank you.

[The following was subsequently received:]

For purposes of the crude oil windfall profit tax, "heavy" oil is defined as oil with a gravity of 16 degrees API (American Petroleum Institute) or less, corrected to 60 degrees Fahrenheit. (Oil with a lower API degree rating is thicker and has a greater density than oil with a higher rating.) Heavy oil is taxed as tier three oil, at a rate of 30 percent of the windfall profit. The windfall profit tax does not distinguish between types of firms that produce heavy oil—both majors and independents are taxed at the same 30 percent rate. In general, there are no code provisions that explicitly distinguish between heavy oil produced by an independent and that produced by a major. To the extent that heavy oil is produced from a stripper well, however, the independent firm will have an advantage because of the independent stripper exemption.

A second issue related to the taxation of heavy oil is the proper dividing line between heavy and other oil. Oil that has an API rating of between 16 and 20 degrees is typically referred to as heavy oil by operators in the petroleum industry; however, this definition is not carried over to the tax code. Only oil with a gravity less than 16 degrees is considered heavy oil for purposes of the windfall profit tax. Thus, it is only this oil that is eligible for the lower 30 percent rate and the more generous base price escalator allowed for heavy oil.

In order to show the tax advantages that go with classification as heavy oil, the following table shows two identical wells that are assumed to produce oil with a gravity of 17 degrees. This is heavy oil by industry standards, but not by the definition used for the current windfall profit tax. The first well is taxed as if it did qualify as heavy oil under tax code standards, while the second well is taxed as it would be under current law—i.e., the well is taxed as old (tier one).[1] The calculation of the taxes is based on the discounted cash flow (DCF) model used for CBO's testimony and in the detailed Analysis of Special Tax Provisions Affecting Independent Oil and Gas Producers.

The taxes paid by the independent corporation on the first well differ very little from those paid by the integrated firm—on a per-barrel basis the difference is $0.20. Because heavy oil is treated the same for each type of firm, they each pay the same amount in windfall profit taxes—$17,700. Thus, the difference that arises between the independent and the integrated corporation is due to other tax provisions, such as percentage depletion and the amortization of intangible drilling costs, and not to the windfall profit tax.

The second well in the table has the same production characteristics as the first well except that its production is treated as old (tier one) oil for purposes of the windfall profit tax. The tax on the second well's production is higher than the first because it is taxed at the higher tier one rates, and because the windfall profit (as defined by the tax code) is higher. This is due to the more generous base price escalator allowed oil classified as heavy as opposed to tier one oil. On a per-barrel basis, the total difference in tax between the two types of oil is $1.02 for the integrated firm and $0.63 for the independent corporation. These results from the DCF model indicate that tax payments can be significantly different depending upon whether a well produces oil with a gravity of greater or less than 16 degrees API.

In general, the windfall profit tax burden is less on heavy oil (less than 16 degrees) than it is on other oil. In the second quarter of 1982 (the latest quarter for which data are available), the average windfall tax per barrel of heavy oil was $1.25 (5.6 percent of its removal price).[2] In contrast, the average for all oil production was $6.01 per barrel for 21.5 percent of its wellhead price. The tax on heavy oil tends to be lower than for other oil because of its low tax rate and because the windfall profit (as defined by the law) is a smaller percentage of the removal price than it is for other types of oil.

## ESTIMATED PRESENT VALUE OF TAXES FOR TWO OIL WELLS

[In thousands of dollars, except as noted]

| Type of producer | 17 degrees API oil well (taxed as heavy oil) [1] | 17 degrees API oil well (taxed as old oil) |
|---|---|---|
| Integrated corporation: | | |
| Corporate income tax | $378.1 | $287.4 |
| Add-on minimum tax | 0 | 0 |

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[1] It should be noted that oil with a gravity of between 16 and 20 degrees is not subject to a tax disadvantage (when compared to heavy oil) if it happens to qualify as either newly discovered oil or incremental tertiary oil, since it would then be eligible for the same favorable tax rules that apply to heavy oil.

[2] U.S. Department of Treasury, Internal Revenue Service, *SOI Bulletin*, Spring 1983.

## ESTIMATED PRESENT VALUE OF TAXES FOR TWO OIL WELLS—Continued

[In thousands of dollars, except as noted]

| Type of producer | 17 degrees API oil well (taxed as heavy oil) [1] | 17 degrees API oil well (taxed as old oil) |
|---|---|---|
| Windfall profit tax | 17.7 | 266.3 |
| Personal income tax | 255.5 | 209.7 |
| Total taxes | 651.4 | 763.4 |
| Tax per barrel (dollars) | 5.95 | 6.97 |
| Tax rate [2] (percent) | 56 | 63 |
| Independent corporation: | | |
| Corporate income tax | 343.1 | 263.7 |
| Add-on minimum tax | 5.1 | 8.7 |
| Windfall profit tax | 17.7 | 190.2 |
| Personal income tax | 264.2 | 236.1 |
| Total taxes | 630.1 | 698.8 |
| Tax per barrel (dollars) | 5.75 | 6.38 |
| Tax rate [2] | 55 | 59 |
| Sole proprietorship or partnership: | | |
| Corporate income tax | 0 | 0 |
| Add-on minimum tax | 0 | 0 |
| Windfall profit tax | 17.7 | 190.2 |
| Personal income tax | 341.8 | 276.0 |
| Total taxes | 359.5 | 466.2 |
| Tax per barrel (dollars) | 3.28 | 4.26 |
| Tax rate [2] | 35 | 43 |
| Property characteristics: | | |
| Peak production (barrels per day) | 35 | 35 |
| Initial reserves (barrels) | 109,513 | 109,513 |
| Oil tier classification | 3 | 1 |
| Drilling investment (producing well) | 130 | 130 |
| Drilling investment (dry well(s)) | 100 | 100 |
| Depreciable equipment | 90 | 90 |
| Inflation rate (percent) | 5 | 5 |
| Discount rate (or hurdle rate) (percent) | 12.5 | 12.5 |
| Initial removal price (dollars) | 22.00 | 22.00 |

[1] Although this well does not produce heavy oil, as currently defined, for comparative purposes it is assumed that the well is subject to the tax rules that apply to wells that produce oil with a gravity of less than 16 degrees.

[2] The tax rate is the percentage difference between the pretax and posttax rate of return on the total investment, based on a corporate tax rate of 46 percent and a personal tax rate of 50 pct.

Note.—For further details on the methods used to calculate these tax payments, see app. III.

Chairman Rangel. Mr. Campbell.

Mr. Campbell. Thank you, Mr. Chairman. I won't take but just a moment.

Dr. Rivlin, let me ask a little different type of question.

Our windfall profit taxes today are about 50 percent below the estimate given by your group when we originally passed them.

What do your figures say as to the levels of the taxes paid by the major integrated oil companies versus the original estimates on your independents?

Ms. Rivlin. First, you are right that the windfall profit tax revenues are lower than everybody thought they were going to be because the price of oil is not as high as it was estimated to be.

I don't know the answer to the second part of the question. Let's see if one of my staff does.

Mr. Lucke. I don't think I quite understand the question.

Mr. Campbell. I want to know if your original estimate on revenues from the windfall profit tax is lower or what the margin of difference is in your estimate of the revenue from the larger integrated companies versus revenue you would get from the independents.

In other words, did you lose the same amount of revenue from the independent companies' as you lost from the integrated companies?

Mr. LUCKE. I would have to work through that.

[The following was subsequently received:]

The Crude Oil Windfall Profit Tax was originally estimated to raise $228 billion over 1979–90 period. CBO's January 1983 baseline revenue forecast estimates that the tax will raise $37.7 billion over the 1983–88 period, or only 28 percent of the $134.1 billion that was initially expected over the same years. (CBO's baseline forecast does not extend past fiscal year 1988.) This large revision is due to much lower oil price assumptions than those made when the act was originally passed.

For purposes of the tax code, an "independent" is defined as a nonintegrated firm, and the taxes paid by the independents refer only to those paid on their first 1,000 barrels per day of production. Although, some independents produce more than 1,000 barrels per day, favorable tax provisions only apply to their first 1,000 barrels. The independent oil companies were expected to bear about 9 percent ($20 to $22 billion) of the liability when the tax was first enacted. This is confirmed by statistics compiled by the Internal Revenue Service (IRS) for the first and second quarters of 1982 (the latest quarters for which data are available) that indicate that the independents paid about 9 percent of the actual gross windfall profit tax liability in each of those quarters.[1] Because of the way the tax is structured the independents' tax share would not be expected to fluctuate greatly in response to changes in the price of oil.

The Economic Recovery Tax Act of 1981, however, exempted all independent stripper production from the windfall profit tax starting in 1983. The exemption of all stripper production by independents reduces their prospective share of windfall profit tax revenues from 9 percent to about 5 to 6 percent—a reduction of more than one-third. Thus, the projected decline in the share of windfall profit taxes paid by the independents results primarily from a change in the law, rather than from a downward revision in the forecasted price of oil.

Mr. CAMPBELL. I would appreciate it if you would work through it.

As I look at the discovery and the production and the things that are taking place, it appears to me that discovery, by independents, and general production levels may have been helped pretty well, and you may have lost revenues from the integrated companies.

I think that would fly in the face of some economic arguments made of doing away with the taxation. I think it would be very helpful if you work through it for us.

The second thing I would like to know is the price paid at the wellhead by the independents.

I would like for you to look at what the impact from shutting down some of the independent refineries and causing them to go back through your major refineries is having on the overall equation; namely the price of oil. Is it having an adverse impact on the independents? If we were to do anything to change the differential in tax that they have, would that not in fact only strengthen the majors and serve to push more independents out?

Ms. RIVLIN. We will take a look at that and try to give you an answer for the record.

Mr. CAMPBELL. Thank you. I didn't expect to surprise you here but I would like to have both of them answered.

Thank you, Mr. Chairman.

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[1] U.S. Department of Treasury, Internal Revenue Service, SOI Bulletin, Winter 1982–83 and Spring 1983.

[The following was subsequently received:]

The independents do not appear to receive a lower price for their oil than do the majors. For example, in the second quarter of 1982 (the latest quarter for which data are available), the average removal price of tier one (old) oil (other than Prudhoe Bay) was $31.15 per barrel for the independents and $30.17 per barrel for the integrated firms. On tier two (stripper) oil, the independents received $30.70 per barrel compared to $30.06 for the majors.[1] The independents also had higher wellhead prices for tier one and tier two oil for the first quarter of 1982 and for 1981 (see the table below). This rough evidence suggests that the prices received by the independents have not been reduced to below those received by the majors as a result of fewer independently owned refineries.

AVERAGE REMOVAL PRICE PER BARREL BY OIL TIER AND TYPE OF PRODUCER

[In dollars]

| Oil tier and producer type | Year and quarter | | |
|---|---|---|---|
| | 1981 (all) | 1982:1 | 1982:2 |
| Tier 1, (old oil):[1] | | | |
| Integrated | $33.03 | $32.09 | $30.17 |
| Independent | 34.18 | 33.22 | 31.15 |
| Tier 2 (stripper oil): | | | |
| Integrated | 33.29 | 32.14 | 30,06 |
| Independent | 33.49 | 33.05 | 30.70 |

[1] Excludes Prudhoe Bay production.

Source: U.S. Department of Treasury, Internal Revenue Service, SOI Bulletin, Summer 1982, Winter 1982-83, and Spring 1983 issue.

Chairman RANGEL. Thank you.

Thank you, Doctor, and your staff.

As pointed out, the members have reserved the right to forward to your office some questions.

Ms. RIVLIN. Thank you, Mr. Chairman, and let us know if there is anything else you need.

Mr. THOMAS. Mr. Chairman, as an example to illustrate some of the concerns the gentleman from Carolina has, as does the gentleman from California, one brief example to indicate the good old unforeseen consequences of changing tax policy for equitability purposes.

Under the windfall profit tax there was no consideration for heavy oil production in terms of tertiary recovery steam heating, and there were a number of very small independent refineries in the business of doing nothing but converting crude oil to bunker fuel, residual fuel oil for use in burning in oilers for the production of steam for the increased production of oil.

When the windfall profit tax went into place, there was no exemption for this oil which was essentially recycled within the industry.

In fact, if the crude oil left the property there was a tax placed on it. It became uneconomic for the smaller independent refineries, who simply knock off the light crudes off the top and burn the residual oil, to do what they were doing, and what happened in fact was, these companies began burning crude oil in the boilers.

Less efficient Btu's, more emission problem, consumption of the raw product, all to avoid a tax which was put on for equitable purposes.

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[1] U.S. Department of Treasury, Internal Revenue Service, *SOI Bulletin,* Spring 1983.

We have not been able to change that windfall profit tax. A number of small refineries have gone out of business, air pollution is a greater problem, and we are consuming more oil to do the same thing we were doing before.

I think we need to think through this business of equitability on taxes.

Thank you, Mr. Chairman.

Chairman **Rangel**. Thank you again, Doctor.

[CBO submitted the following in response to the subcommittee's request:]

U.S. Congress,
Congressional Budget Office,
*Washington, D.C., July 22, 1983.*

Hon. Charles B. Rangel,
*Chairman, Subcommittee on Oversight, Committee on Ways and Means, U.S. House of Representatives, Washington, D.C.*

Dear Mr. Chairman: In response to your request of July 11, 1983, for information regarding independent oil and gas producers, we are pleased to provide the enclosed analysis. The analysis is organized in the order presented in your letter.

I hope this information is useful to your Subcommittee in its review of the taxation of independent oil and gas producers. If you or your staff have any further questions, please contact Robert Lucke at 226-2680.

Sincerely,

Alice M. Rivlin,
*Director.*

## Comparison of the Reinvestment Rates of the Various Oil and Gas Producers

In general, the smaller oil and gas companies tend to spend a greater percentage of their oil and gas revenues on exploration, development, and production expenditures than do the larger integrated firms. Table 1 presents a comparison of the revenues and expenditures for three groups of companies in the oil and gas industry: the largest 50 (the major integrate firms), the next 150 (the bigger independents), and all the rest (the smaller independents). In 1981, the largest firms spent 84 percent of their revenues on oil and gas expenditures versus about 120 percent for the independents. For comparsion, in 1980, the larger firms spent 80 percent as against about 100 percent for the independents. These ratios are typically referred to as "reinvestment" rates.

A company's reinvestment rate can exceed 100 percent of its lease revenues because firms can issue new stock or borrow to raise cash to cover the shortfall. Firms that borrow heavily to finance new expenditures will have reinvestment rates. For example, a new or growing firm can have relatively high expenditures and low revenues because new investments take time to pay off. Because many of the independents are relatively new and growing, as well as heavily debt financed, it is expected that they will continue to have high reinvestment ratios.

On the other hand, the majors are well established firms with long records of prior investments, enabling them to earn substantial revenue from previously developed properties. In addition, the majors usually have much higher dividend payout rates than the independents. The majors also tend to invest in their other lines of business, such as refining or chemicals. For these reasons, the reinvestment ratios of the major companies are below those of their independent counterparts.

## A COMPARSION OF THE RATE OF RETURN ON INVESTMENTS FOR DIFFERENT TYPES OF OIL AND GAS PRODUCERS

One of the measures that financial analysts use to measure the rate of return for companies is the ratio of a firm's after-tax income to its net worth. This measure reflects a company's return on stockholders' equity.

In order to compare the profitability of the majors and the independents, CBO examined the 1981 and 1982 earnings of 60 oil and gas firms—19 majors and 41 independents. The independents were split into two groups—those firms with above $200 million in assets and those with less than $200 million. The net income and equity data were as reported by the firms in their annual financial reports.

Table 2 sets out the rates of return for the three groups of companies. In 1982, the independents taken together earned a return of 11.9 percent versus 13.0 percent for the majors. The big independents earned a 12.4 percent rate compared to only 5.8 percent for the smaller firms. All the 1982 rates are significantly lower than in 1981. The majors earned a 17.7 percent rate in 1981; the independents earned a slightly lower rate (17.3 percent). Again, the rate of return for the small independents (11.2 percent) lagged significantly behind the other groups. On average, it appears that both the majors and the large independents earn comparable returns, while the smaller companies earn significantly less. The results for individual firms, however, may differ significantly from these general results.

Two caveats to the returns shown in Table 2 should be noted. As with any sample of companies, the results depend upon which firms are chosen. A different sample could yield different results. It may, therefore, be worthwhile to study a larger number of firms. Secondly, some adjustments to net income may be desirable to account for differences between a firm's reported tax expense and its actual tax payment. To the extent that a firm's tax expense exceeds its actual payments, its net income will be understated, and vice versa. This can occur because of differences in the tax and financial reporting of items such as depletion and drilling costs. Consequently, further examination of company records may yield a more definitive measure of net income. In addition to these two considerations, it must be stressed that the results for only two years do not necessarily reflect the long-run profit trends in the industry.

## INCENTIVE EFFECTS OF PERCENTAGE DEPLETION FOR PRODUCTION IN EXCESS OF 1,000 BARRELS PER DAY

Current tax law allows independent oil and gas producers percentage depletion on their first 1,000 barrels of oil production (or an equivalent amount of natural gas). In 1983, the depletion rate is 16 percent and falls to 15 percent for 1984 and years thereafter. This means that independent producers are allowed to deduct from their income 15 percent of the gross revenue earned from their first 1,000 barrels of production. This effectively allows small producers to exclude 15 percent of their oil and gas revenue from their taxable income.

Percentage depletion offers producers of less than 1,000 barrels per day an incentive to increase their production because they are only taxed on 85 percent of the resulting revenue. Thus, small firms (less than 1,000 barrels of production per day) produce more oil and gas than they would without percentage depletion, although it is not clear how much more. Once a firm has crossed the 1,000 barrel-per-day threshold, however, percentage depletion no longer offers any incentive to increase production. This is because all production over 1,000 barrels per day is subject to full taxation.

Although most independents produce less than 1,000 barrels per day, as many as 100 large independents may produce in excess of that amount. For these companies, the percentage depletion allowance offers no incentive to increase their production, but merely acts to lower their taxes. In other words, these companies have no marginal incentive to increase their output. For those independents with production under 1,000 barrels per day, however, the depletion allowance works as an incentive until they reach the cut-off point.

## ANY STATISTICS ON THE NUMBER OF STRIPPER WELLS DRILLED BEFORE AND AFTER IMPLEMENTATION OF THE JANUARY 1, 1983 WINDFALL PROFIT TAX STRIPPER WELL EXEMPTION FOR INDEPENDENTS, AND A COMPARISON OF WHAT PROPORTION OF INDEPENDENT PRODUCTION WAS STRIPPER WELL PRODUCTION BEFORE AND AFTER THE EXEMPTION EFFECTIVE DATE

Although there are current statistics on well completions, there are no data on their initial production levels. It cannot be determined how many new wells are stipper wells (wells that produce 10 barrels per day).

As far as stripper production is concerned, the data are not currently available to estimate the effect of the stripper exemption. The most recent data (1981) indicate that for companies other than the top 50 firms, about 33 percent of their production was from stripper wells.[1] Comparable data for 1983 will not be available until 1985. Although the stipper exemption offers an incentive for independents to increase their stripper production, the effect of the exemption cannot be calculated at present.

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[1] U.S. Department of Commerce, Bureau of the Census, *Annual Survey of Oil and Gas, 1981,* Table 6A.

Table 1.—COMPARISON OF COMPANY LEASE REVENUES AND EXPENDITURES (1981 and 1980) [1]

[Dollar in millions]

| | Year | First 50 companies | Companies 51 to 200 | All other companies |
|---|---|---|---|---|
| Lease revenues | 1981 | $88,373.4 | $10,297.9 | $9,820.9 |
| | 1980 | 60,848.5 | 7,257.4 | 6,797.1 |
| Expenditures (capitalized and expensed) | 1981 | 74,393.9 | 12,348.5 | 11,893.3 |
| | 1980 | 48,837.8 | 7,681.8 | 6,135.4 |
| Ratio of expenditures to lease revenues (percent) | 1981 | 84 | 120 | 121 |
| | 1980 | 80 | 106 | 90 |

[1] Groups of companies are determined according to their total lease revenues. Both revenues and expenditures are on a net company basis.

Source: U.S. Department of Commerce, Bureau of the Census, "Annual Survey of Oil and Gas", 1980 and 1981 editions.

Table 2.—COMPARISON OF RATES OF RETURN FOR MAJOR AND INDEPENDENT OIL AND GAS COMPANIES [1]

| | 1981 [1] | 1982 [2] |
|---|---|---|
| Majors (19 firms) | 17.7 | 13.0 |
| Independents (41 firms) | 17.3 | 11.9 |
| Large independents (22 firms) | 17.8 | 12.4 |
| Small independents (19 firms) | 11.2 | 5.8 |

[1] Rate of return is measured by annual net income after taxes divided by stockholder equity (end of the year).

[2] Year as defined by each corporation's fiscal calendar.

NOTE.—Major Companies: Exxon, Mobil Oil, Texaco, Standard of California, Standard of Indiana, Gulf Oil, Shell Oil, ARCO, Tenneco, Standard of Ohio, Sun Oil, Phillips Petroleum, Getty Oil, Occidental Petroleum, Union Oil, Amerada Hess, Pennzoil, Kerr McGee, and Murphy Oil.

Large Independents: Superior Oil, Louisiana, Land and Exploration, Mitchell Energy and Development, Mesa Petroleum, Pioneer Corporation, Pogo Producing, Entex, General American Oil Company of Texas, Apache Corp., Forest Oil, Crystal Oil, Lear Petroleum, Amarex, Adobe Oil and Gas, Hiamilton Brothers, Sabine Corp., Moran Energy, Damson Oil, Universal Resources, Dyco Petroleum, Woods Petroleum, and Wainoco Oil.

Small Independents: May Petroleum, Felmont Oil, Texas American Energy, Howell Petroleum, Sage Energy, Seneca Oil, Fauley Petroleum, Galaxy Oil, Prairie Producing, Beard Oil, Energy Minerals, Hershey Oil, Statex Petroleum, AmQuest, Ike Lovelady, Argonaut Energy, Baruch-Foster, Wichita Industries, and Norris Oil.

Source: Company Annual Financial Reports.

Chairman RANGEL. From the Department of the Treasury, the Honorable J. Gregory Ballentine, accompanied by the Honorable William McKee.

We welcome you back, Mr. Ballentine, to our subcommittee hearing.

We have a copy of your statement. You can proceed as you would feel most comfortable.

## STATEMENT OF J. GREGORY BALLENTINE, DEPUTY ASSISTANT SECRETARY FOR TAX ANALYSIS, DEPARTMENT OF THE TREASURY

Mr. BALLENTINE. Mr. Chairman, I will summarize my statement and submit the written statement for the record.

Chairman RANGEL. Without objection.

Mr. BALLENTINE. I am pleased to have the opportunity to discuss the taxation of oil and gas producers.

Before addressing the economic and revenue consequences of various oil tax provisions, I will briefly summarize them for the committee.

First, percentage depletion is a method by which a taxpayer holding an economic interest in a mineral property is allowed to recover his basis in the property.

Under the Internal Revenue Code, the depletion deduction is computed either as cost depletion or percentage depletion.

Under the percentage depletion method, a fraction of the gross value of the oil sold is allowed as a deduction. One significant difference between cost and percentage depletion is that the deduction for percentage depletion is allowable even after a taxpayer recovers all his basis in the property.

In 1975 Congress repealed percentage depletion for all integrated oil and gas producers. Certain exemptions were provided for independent producers and royalty owners.

The amount of oil or gas eligible for percentage depletion was initially set at 2,000 barrels per day of oil, or its gas equivalent.

The applicable depletion rate, initially 22 percent, has been reduced to 16 percent for this year and will be further reduced to 15 percent for 1984 and thereafter.

Percentage depletion in excess of the adjusted basis of the property is a preference item for the alternative minimum tax applicable to individuals and the corporate minimum tax.

In the case of integrated oil companies, companies that do not meet the independent producer definition, 15 percent of the amount otherwise allowable as a deduction for intangible drilling costs are required to be capitalized and deducted ratably over a 36-month period beginning with the month the costs are paid or incurred. The provision does not apply to nonproductive wells.

In the case of individuals, intangible drilling costs in excess of the amount amortizable with respect to the cost and in excess of net income from oil and gas production, are subject to the alternative minimum tax.

However, individuals may avoid the preference tax if they elect to amortize intangible drilling costs over 10 years and some may treat all or part of such costs as attributable to recovery property in the 5-year ACRS class.

If the ACRS election is made, the investment tax credit is available in the year the property is placed in service.

The windfall profit tax consists of 3 tiers of tax; tier 1, applicable to previously controlled oil; tier 2, primarily stripper well oil; and tier 3, which consists of newly discovered, heavy and incremental tertiary oil. The adjusted windfall profit tax base is subject to a tax of 70 percent for tier 1 oil, 60 percent for tier 2 oil and 30 percent for tier 3 oil, except that the rate applicable to newly discovered oil is reduced to 25 percent for 1983 and will decrease to 15 percent in 1986 and thereafter.

However, independent producers' working interests are subject to only a 50-percent rate of tax on up to 1,000 barrels per day of production of tier 1 oil and they are fully exempt from tax on all stripper well production.

Holders of royalty interests who are individuals are also exempt from tax on up to two barrels per day of production. This exemption will be increased to three barrels per day after 1984.

While this hearing focuses on tax provisions that differentiate among types of oil producers, it is worth commenting briefly on the taxation of returns to domestic oil producers compared to taxation of returns to investment in other industries.

Prior to the past decade, the Tax Code generally favored investment in domestic oil and gas production relative to other industries.

The two main sources of this preferential treatment were the provisions that allowed percentage depletion and the fact that oil and gas producers were allowed to expense rather than to capitalize intangible drilling and development costs.

Beginning with the Tax Reform Act of 1969, when percentage depletion allowances were reduced, there have been a number of tax changes that have eroded the overall advantage previously afforded to domestic oil and gas production.

Percentage depletion has been eliminated for integrated producers and is being phased down to 15 percent for the first 1,000 barrels per day of output to independent producers and royalty interests.

Moreover, since enactment of the Economic Recovery Tax Act of 1981, the relative advantage provided to domestic oil production compared to many other investments, by expensing of intangible drilling and development costs, has virtually disappeared. This is because 3-year and 5-year ACRS property is taxed almost equally favorably when the benefits of the investment tax credit are included.

Finally, the decontrol of oil was accompanied by the Crude Oil Windfall Profit Tax of 1980, a special excise tax on revenue from domestic oil production.

As a result of all these changes, especially the windfall profit tax and the incentives provided to investment by ACRS, it can no longer be asserted as a general proposition that the tax system favors investment in domestic oil and gas production.

I will now comment on specific provisions that differentiate between independent producers and major integrated companies.

In terms of working interests in oil production, about 75 percent of domestic production is accounted for by the integrated producers and the remaining 25 percent by independents.

Further, although there is no hard evidence on the size distribution of independents, data from windfall profit tax reports suggest that well over 60 percent of independent production is accounted for by firms producing less than 1,000 barrels per day.

With respect to producing interests, percentage depletion and the lower rates under the windfall profit tax on tier 1 oil and stripper oil are available only for the first 1,000 barrels per day of output by independent producers. As a result, these special provisions provide no direct production incentive to integrated companies or to independent producers with output of 1,000 barrels per day or greater.

The rules relating to expensing of intangible drilling and development costs provide a substantial incentive to domestic oil production compared to a set of accounting rules that measures income more accurately by requiring oil producers to capitalize such costs and then claim deductions over the productive life of the property.

However, as I have mentioned, expensing is currently not significantly more favorable than the combination of depreciation deductions and the investment credit available for 3-year and 5-year ACRS property.

Moreover, current rules relating to IDC's do not substantially alter relative returns available to majors and independents from oil well development.

For corporations, integrated producers may expense only 85 percent of IDC's, but can deduct the remaining 15 percent over 36 months; independents are permitted full expensing.

At a 10-percent discount rate, this makes the present value of deductions per dollar of IDC's for major corporations equal to 98.7 cents compared to a deduction worth $1 for an independent producer allowed to expense IDC's. Similarly, the option available to some noncorporate producers—a 5-year writeoff with an investment tax credit—provides an incentive very close to the incentive resulting from expensing.

As noted the windfall profit tax imposes lower tax rates on tier 1 oil produced by independent producers, does not tax stripper oil produced by independent producers, and allows a 2-barrel per day exemption, scheduled to increase after 1984 to 3 barrels per day, for royalty interests.

The effect on production incentives of the differential taxation of independent and major producers is relatively small because tier 3 oil is taxed at the same rate for both types of producers, while production of tier 1 oil is probably less affected by changes in the tax.

The exemption for stripper well production by independent producers was intended to prevent the premature abandonment of properties. There is no special geological or other feature that distinguishes a stripper well from other properties; they are merely wells with output of less than 10 barrels per day.

Stripper wells are usually, but not always, oil wells in the latter stages of their productive lives, where output rates have declined and, in some cases, costs of extraction have risen.

In the absence of the stripper well exemption, the windfall tax would cause some wells to be shut down that would otherwise continue to operate.

The exemption for royalty owners enacted in 1980 and expanded in 1981 was primarily intended to relieve the hardship imposed by the tax on low and middle income recipients of royalty income from small property holdings.

The increased income received by these individuals from decontrol and higher world oil prices was not regarded as a major windfall. It was recognized that in many cases this exemption would provide little incentive for additional oil production.

The special tax provisions available only for independent producers and royalty owners—percentage depletion, the reduced tax rate on tier 1 oil under the windfall profit tax, the exemption of stripper oil from the windfall profit tax, and the exemption of some output attributable to royalty interest of some output attributable to royalty interests from the windfall profit tax reduce Federal revenue by $3 billion in fiscal year 1983, $2.3 billion in fiscal year 1984, $2.2 billion in fiscal year 1985, $2.3 billion in fiscal year 1986 and $2.3 billion in fiscal year 1987.

In the January budget, these provisions were estimated to reduce Federal revenues by a much larger amount—$4 billion in fiscal year 1983, $3.5 billion in 1984, $3.9 billion in fiscal year 1985, $4.1 billion in fiscal year 1986, and $4.4 billion in fiscal year 1987.

The decline in the estimated revenue cost since January results because both the projected value of percentage depletion deductions and the expected foregone revenue from exemptions to the windfall profit tax have fallen due to the decline in the world oil price.

The most costly of these provisions is percentage depletion, which accounts for about two-thirds of the revenue loss.

The January budget estimates also show a substantial revenue loss from expensing of intangible drilling costs of oil and gas wells—$1.5 billion in fiscal year 1983; $1.2 billion in fiscal year 1984; $1.3 billion in fiscal year 1985; $1.4 billion in fiscal year 1986, and $1.7 billion in fiscal year 1987.

This method of estimating the revenue costs of allowing expensing of IDC's in effect assumes that taxpayers currently using percentage depletion as a method of cost recovery would lose the entire value of the IDC deduction, not just the timing benefit of expensing, if expensing of IDC's were eliminated.

Since the amount of percentage depletion deductions permitted is not constrained by a taxpayer's basis in the property, it is presumed that percentage depletion in many cases would continue to be more advantageous than cost depletion even if IDC's that the taxpayer were no longer allowed to expense were added to the depletable basis.

Therefore, the additional cost depletion deductions that might otherwise result from including IDC's in the depletable basis would be wasted.

As a result, the method of estimating the revenue cost of IDC's in the tax expenditure budget overstates the timing benefit that results from allowing IDC's to be expensed rather than capitalized and recovered by cost depletion over the life of the property. If it were assumed that the alternative to expensing IDC's would be to allow IDC's to be recovered by cost depletion, with no effect on allowable percentage depletion deductions, the estimated revenue loss from expensing of IDC's would be much smaller than the loss shown in the budget—$855 million in fiscal year 1983, $550 million in fiscal year 1984, $626 million in fiscal year 1985, $700 million in fiscal year 1986, and $915 million in fiscal year 1987.

The administration is currently preparing a study on the effects of decontrol and the crude oil windfall profit tax on domestic oil production, oil imports, inflation, employment, economic growth, Federal revenues, and national security.

This study, being prepared in response to a congressional mandate, contained in the Crude Oil Windfall Profit Tax Act of 1980, is not yet completed and I cannot therefore discuss its findings in any detail or provide any quantitative estimates other than estimates of Federal revenue from the windfall profit tax. However, I can discuss in general terms the conclusions we are reaching.

Generally, the administration study will show that decontrol increased domestic oil production, reduced oil imports, and increased economic growth, compared to the levels that would have been experienced if pre-1979 price controls had been continued.

Thank you.

[The prepared statement follows:]

## STATEMENT OF J. GREGORY BALLENTINE, DEPUTY ASSISTANT SECRETARY (TAX ANALYSIS), DEPARTMENT OF THE TREASURY

Mr. Chairman and members of the committee, I am pleased to have the opportunity to discuss the taxation of oil and gas producers.

The subcommittee has expressed an interest in examining the amendments to the tax laws that were enacted subsequent to 1975 and that have had the effect of distinguishing between integrated oil companies and independent producers.

Before addressing the economic and revenue consequences of these provisions, I will briefly summarize them for the subcommittee.

### CURRENT LAW

*Percentage depletion*

The deduction for depletion is the method by which a taxpayer holding an economic interest in a mineral property is allowed to recover his basis in the property. Under the Internal Revenue Code, the depletion deduction is computed either as cost depletion or percentage depletion. Under cost depletion, in the case of oil, the total unrecovered depletable cost is divided by the estimated recoverable barrels of oil on the property. This depletion unit cost is multiplied by the total barrels sold during the year to compute allowable cost depletion deductions in any year.

Under the percentage depletion method, a fraction of the gross value of the oil sold is allowed as a deduction. One significant difference between cost and percentage depletion is that the deduction for percentage depletion is allowable even after a taxpayer recovers all his basis in the property.

In 1975 Congress repealed percentage depletion for all integrated oil and gas producers. Certain exemptions were provided for independent producers and royalty owners. In general, independent producers are those who are not retailers or refiners or are not related to retailers or refiners. The amount of oil or gas eligible for percentage depletion was initially set at 2000 barrels per day of oil (or its gas equivalent). Beginning in 1980 and for all subsequent years that amount is set at 1000 barrels per day.

The applicable deplection rate, initially 22 percent, has been reduced to 16 percent for this year and will be further reduced to 15 percent for 1984 and thereafter.

The provision retaining percentage depletion for independent producers containes transfer rules which are intended to prevent proliferation of the right to claim percentage depletion. In general, these rules provide that a transfer of an interest in any proven oil or gas property will preclude the transferee from taking into account any production attributable to that interest in calculating allowable percentage depletion.

Percentage depletion in excess of the adjusted basis of the property is a preference item for the alternative minimum tax applicable to individuals and the corporate minimum tax.

*Intangible drilling costs*

Under section 263(c) if the Internal Revenue Code all producers of oil and gas who hold a working or operating interest are granted the option to expense rather than capitalize their intangible drilling and development costs. Intangible drilling and development costs generally constitute costs incurred for wages, fuel, repairs, hauling, supplies, and similar costs, incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas.

In the case of integrated oil companies (companies that do not meet the independent producer definition), 15 percent of the amount othewise allowable as a deduction for intangible drilling costs are required to be capitalized and deducted ratably over a 36-month period beginning with the month the costs are paid or incurred. The provision does not apply to nonproductive wells.

In the case of individuals, intangible drilling costs in excess of the amount amortizable with respect to the cost and in excess of net income from oil and gas production, are subject to the alternative minimum tax. However, individuals may avoid the preference tax if they elect to amortize intangible drilling costs over 10 years and some may treat all or part of such costs as attributable to recovery property in the 5-year ACRS class. If the ACRS election is made, the investment tax credit is available in the year the property is placed in service.

All producers are subject to recapture of intangible drilling costs upon the disposition of the property to which such costs relate. Finally, the at-risk limitations are applicable to individuals and closely-held corporations. Such taxpayers may deduct losses incurred in an oil and gas activity only to the extent that the taxpayer is considered to be at risk with respect to such activity.

### *Windfall profit tax*

The windfall profit tax consists of three tiers of tax; tier one, applicable to previously controlled oil; tier two, primarily stripper well oil; and tier three, which consists of newly-discovered, heavy and incremental tertiary oil. The adjusted windfall profit tax base is subject to a tax of 70 percent for tier one oil, 60 percent for tier two oil and 30 percent for tier three oil, except that the rate applicable to newly-discovered oil is reduced to 25 percent for 1983 and will decrease to 15 percent in 1986 and thereafter.

However, independent producers' working interests are subject to only a 50 percent rate of tax on up to 1000 barrels per day of production of tier one oil and they are fully exempt from tax on all stripper well production. Holders of royalty interests who are individuals are also exempt from tax on up to two barrels per day of production. This exemption will be increased to three barrels per day after 1984.

Finally, first purchasers of oil that are integrated oil companies are required to make semimonthly estimated deposits of the withheld tax. All other first purchasers (generally, independent refiners) are required to make withholding deposits not later than 45 days after the close of the month in which the oil is removed from the premises.

## ECONOMIC AND REVENUE EFFECTS

### *Taxation of domestic oil production: Overview*

While this hearing focuses on tax provisions that differentiate among types of oil producers, it is worth commenting briefly on the taxation of returns to domestic oil production compared to taxation of returns to investment in other industries. Prior to the past decade, the tax code generally favored investment in domestic oil and gas production relative to other industries. The two main sources of this preferential treatment were the provisions that allowed percentage depletion, rather than cost depletion, as a method of recovering certain costs of acquiring and developing oil and gas properties and the fact that oil and gas producers were allowed to expense, rather than to capitalize, intangible drilling and development costs. These provisions had the effect of encouraging the exploration and development of oil properties, relative to investments in other industries.

Beginning with the Tax Reform Act of 1969, when percentage depletion allowances were reduced, there have been a number of tax changes that have eroded the overall advantage previously afforded to domestic oil and gas production. Percentage depletion, at one time 27½ percent of revenue for all producers, has been eliminated for integrated producers and is being phased down to 15 percent for the first 1,000 barrels per day of output to independent producers and royalty interests.

Moreover, since enactment of the Economic Recovery Tax Act of 1981, the relative advantage provided to domestic oil production, compared to many other investments, by expensing of intangible drilling and development costs, has virtually disappeared. This is because 3-year and 5-year ACRS property is taxed almost equally favorably, when the benefits of the investment tax credit are included. Further, as I have mentioned, the Tax Equity and Fiscal Responsibility Act of 1982 imposed additional limits on the benefits taxpayers derive from expensing of intangible drilling and development costs.

Finally, the decontrol of oil was accompanied by the Crude Oil Windfall Profit Tax of 1980, a special excise tax on revenue from domestic oil production.

As a result of all these changes, especially the windfall profit tax and the incentives provided to investment by ACRS, it can no longer be asserted as a general proposition that the tax system favors investment in domestic oil and gas production. Rather, the current tax rules can best be described as a complex set of provisions that provide net advantages, compared to investment in some other industries, for investment in some types of oil property, and net disadvantages for other investments in oil property. Certainly, the windfall profit tax, a tax the President has stated in unwise and one that discourages new exploration and production, has had the effect of reducing returns to domestic oil investment.

I will now comment on specific provisions that differentiate between independent producers and major, integrated companies.

### *Economic effects of incentives for independent producers and royalty owners*

The tax laws distinguished among integrated producers, independent producers, and royalty interests. Further, the tax law has the economic effect of providing different production incentives to smaller independent producers—those with output of less than 1,000 barrels per day—than to the largest independent producers.

Production of oil, in the United States and elsewhere, is predominantly from huge oil fields, most of which have to be found by expensive long-term geological and geophysical investment. These types of properties are predominantly developed by the integrated producers and large independents. In general, the smaller independent producers develop the properties considered too marginal to be developed by the majors or the large independents. In some cases, these producers lease modest tracts of land from farmers or others in the expectation that oil will be found. In other cases, they enter into sharing arrangements with major companies in areas where majors hold leases. Through these varied types of arrangements, independent producers are responsible for a large share of the wildcat wells that are drilled within the United States. Output by the smaller independent producers occurs almost exclusively within the lower 48 states; the majors and large independents account for almost all the Alaskan and offshore production.

In terms of working interests in oil production, about 75 percent of domestic production is accounted for by the intergrated producers and the remaining 25 percent by independents. Further, although there is no hard evidence on the size distribution of independents, data from windfall profit tax reports suggest that well over 60 percent of indpendent production is accounted for by firms producing less than 1,000 barrels per day.

With respect to producing interests, percentage depletion and the lower rates under the windfall profit tax on tier 1 oil and stripper oil are available only for the first 1,000 barrels per day of output by independent producers. As a result, these special provisions provide no direct production incentive to integrated companies or to independent producers with output of 1,000 barrels per day or greater.

The most important of these differential incentives for independent producers is percentage depletion. The 15 percent percentage depletion allowance that will be available for years after 1983 is equivalent to a direct subsidy of about about 15 percent of the value of oil output. Some of this subsidy is offset by the fact that percentage depletion, like cost depletion, is used to recover the taxpayer's investment in oil property. (Percentage differs from cost in that it continues after complete recovery of the investment.) But, in general, the basis of depletion is small relative to the total capital cost of an oil project because intangible drilling and development costs are normally expensed. The rationale for maintaining percentage depletion for independent producers was mainly to provide those producers who generally lack financial resources available to the majors with additional funds to reinvest in drilling and exploration.

The rules relating to expensing of intangible drilling and development costs provide a substantial incentive to domestic oil production compared to a set of accounting rules that measures income more accurately by requiring oil producers to capitalize such costs and then claim deductions over the productive life of the property. However, as I have mentioned expensing is currently not significantly more favorable than the combination of depreciation deductions and the investment credit available for 3-year and 5-year ACRS property. Moreover, current rules relating to IDCs do not substantially alter relative returns available to majors and independents from oil well development. For corporations, integrated producers may expense only 85 percent of IDCs, but can deduct the remaining 15 percent over 36 months; independents are permitted full expensing. At a 10 percent discount rate, this makes the present value of deductions per dollar of IDCs for major corporations equal to 98.7 cents, compared to a deduction worth $1 for an independent producer allowed to expense IDCs. Similarly, the option available to some non-corporate producers—a five-year write-off with an investment tax credit—provides an incentive very close to the incentive resulting from expensing.

As noted, the windfall profit tax imposes lower tax rates on tier 1 oil produced by independent producers, does not tax stripper oil produced by independent producers, and allows a 2 barrel per day exemption, scheduled to increase after 1984 to 3 barrels per day, for royalty interests. The effect on production incentives of the differential taxation of independent and major producers is relatively small because tier 3 oil is taxed at the same rate for both types of producers, while production of tier 1 oil is probably less affected by changes in the tax. For tier 1 oil, most oil developed before 1979, it is profitable to remove most oil from the ground even when 70 percent of additional revenues from post-decontrol price increases are taxed. The 50 percent rate available to independents may cause them to pump somewhat more oil from older properties by encouraging more in-fill drilling. However, there are limits to how much output can be increased by such methods.

The exemption for stripper well production by independent producers was intended to prevent the premature abandonment of properties. There is no special geological or other feature that distinguishes a stripper well from other properties; they are merely wells with output of less than 10 barrels per day. Stripper wells are usually, but not always, oil wells in the latter stages of their productive lives, where output rates have declined and, in some cases, costs of extraction have risen. In the absence of the stripper well exemption, the windfall tax would cause some wells to be shut down that would otherwise continue to operate. On the other hand, even with the 60 percent tax rate on the "windfall profit" of major producers, there are many cases where the cost per barrel from a stripper well could be quite low and the well would continue to operate for many years.

In addition to these marginal production incentives, the lower windfall profit tax rates available to independent producers provide those with less financial resources than the majors with additional cash flow to finance new investments.

The exemption for royalty owners enacted in 1980, and expanded in 1981 was primarily intended to relieve the hardship imposed by the tax on low and middle income recipients of royalty income from small property holdings. The increased income received by these individuals from decontrol and higher world oil prices was not regarded as a major windfall. It was recognized that in, many cases, this exemption would provide little incentive for additional oil production. In those cases where oil rights have already been leased, the recipient of royalty income is a passive recipient of shares of production, who is not deciding on either the amount and type of drilling or the rate of extraction from developed properties. However, in those cases where land has value in an alternative use, the royalty owner exemption could raise after-tax returns to a prospective producer by affecting the terms at which an owner is willing to allow oil development on his property. The same potential increase in prospective returns to producers results from allowing percentage depletion to royalty owners.

In summary, the provisions providing more favorable tax treatement for independent producers do have some positive effect on domestic oil supply. The primary intent of the provisions is to encourage small, independent producers in an industry characterized by many small, and some giant firms, and also to relieve small business and moderate income royalty recipients from an extra tax designed to reduce "windfall" earnings rather than to expand domestic supply.

Since the price of oil is mainly determined by world market conditions, the special provisions available to independents do not significantly affect the price received by integrated producers. Therefore, they do not have a major impact on either the output or earnings of integrated producers. The provisions do increase domestic oil output somewhat, particularly output from smaller fields, and this does raise the share of domestic production accounted for by independents, and reduces to some degree United States oil imports.

Finally, in response to the Committee's inquiry, the Treasury Department has not experienced significant problems in administering the special tax provisions relating to independent oil producers.

*Revenue effects*

The special tax provisions available only for independent producers and royalty owners—percentage depletion, the reduced tax rate on tier 1 oil under the windfall profit tax, the exemption of stripper oil from the windfall profit tax, and the exemption of some output attributable to royalty interests from the windfall profit tax reduce Federal revenue by $3.0 billion in fiscal year 1983, $2.3 billion in fiscal year 1984, $2.2 billion in fiscal year 1985, $2.3 billion in fiscal year 1986 and $2.3 billion in fiscal year 1987. In the January budget, these provisions were estimated to reduce Federal revenues by a much larger amount—$4.0 billion in fiscal year 1983, $3.5 billion in 1984, $3.9 billion is fiscal year 1985, $4.1 billion in fiscal year 1986, and $4.4 billion in fiscal year 1987. The decline in the estimated revenue cost since January results because both the projected value of percentage depletion deductions and the expected foregone revenue from exemptions to the windfall profit tax have fallen due to the decline in the world oil price. The most costly of these provisions is percentage depletion, which accounts for about two-thirds of the revenue loss.

The January budget estimates also show a substantial revenue loss from expensing of intangible drilling costs of oil and gas wells—$1.5 billion in fiscal year 1983, $1.2 billion in fiscal year 1984, $1.3 billion in fiscal year 1985, $1.4 billion in fiscal year 1986, and $1.7 billion in fiscal year 1987. In making this computation of the revenue loss from expensing of intangible drilling costs, it is assumed that, in the absence of expensing producers would be required to capitalize IDCs. The capital costs would be recovered by whatever method is available and most advantageous to taxpayers—whether percentage depletion or cost depletion—for other costs included in the basis for depletion under current law.

This method of estimating the revenue costs of allowing expensing of IDCs in effect assumes that taxpayers currently using percentage depletion as a method of cost recovery would lose the entire value of the IDC deduction, not just the timing benefit of expensing, if expensing of IDCs were eliminated. Since the amount of percentage depletion deductions permitted is not constrained by a taxpayer's basis in the property, it is presumed that percentage depletion in many cases would continue to be more advantageous than cost depletion, even if IDCs that the taxpayer were no longer allowed to expense were added to the depletable basis. Therefore, the additional cost depletion deductions that might otherwise result from including IDCs in the depletable basis would be wasted.

As a result, the method of estimating the revenue cost of IDCs in the tax expenditure budget overstates the timing benefit that results from allowing IDCs to be expensed rather than capitalized and recovered by cost depletion over the life of the property. If it were assumed that the alternative to expensing IDCs would be to allow IDCs to be recovered by cost depletion, with no effect on allowable percentage depletion deductions, the estimated revenue loss from expensing of IDCs would be much smaller than the loss shown in the budget—$855 million in fiscal year 1983, $550 million in fiscal year 1984, $626 million in fiscal year 1985, $700 million in fiscal year 1986, and $915 million in fiscal year 1987.

These budget estimates do not represent the cost of the differential treatment allowed to independent producers, compared to major, integrated oil companies. If independent producers were allowed the same rules for recovering intangible drilling costs as integrated corporations—i.e., were allowed to expense 85 percent of IDCs and then deduct the remaining 15 percent over a 36 month period—the increase in Federal revenues compared to current law would be only a small fraction of the total reported revenue cost from expensing of IDCs.

Finally, the difference in the application of at-risk rules to independent and major producers is estimated to have a negligible effect on Federal revenue.

## WINDFALL PROFIT TAX STUDY

The Administration is currently preparing a study on the effects of decontrol and the crude oil windfall profit tax on domestic oil production, oil imports, inflation, employment, economic growth, Federal revenues, and national security. This study, being prepared in response to a Congressional mandate contained in the Crude Oil Windfall Profit Tax Act of 1980, is not yet completed and I cannot therefore discuss its findings in any detail or provide any quantitative estimates, other than estimates of Federal revenue from the windfall profit tax. However, I can discuss in general terms the conclusions we are reaching.

Generally, the Administration study will show that decontrol increased domestic oil production, reduced oil imports, and increased economic growth, compared to the levels that would have been experienced if pre-1979 price controls had been continued. The main reason for these benefits is that ending decontrol and the accompanying entitlements system ended a subsidy that encouraged the use of high-cost imported oil. U.S. consumers, both firms and households, confronted the controlled price, but the value of resources the U.S. economy had to sacrifice to acquire a barrel of imported oil was equal to the world oil price. The end of price controls freed up those resources previously used to produce the export goods needed to pay for expensive imported oil, thereby resulting in more domestric oil production and more production of other goods and services to substitute for reduced oil consumption. As a result, the potential output of the U.S. economy has been increased. Finally, decontrol, by reducing U.S. demand for imports, through its encouragement to both conservation efforts and increased domestic energy production, has helped contribute to the recent decline in world oil prices.

The crude oil windfall profit tax offset some of the stimulus to domestic production provided by oil decontrol. Under the windfall profit tax, prices received by producers are still below the value of oil, as reflected in the world price. Because domestic output is less than it would be if domestic producers recieved the world price, the tax causes some substitution of imports for less costly domestic production. However, unlike controls, the tax does not encourage increased oil consumption. The tax was designed to attempt to minimize the effects on domestic supply by applying a higher tax rate on the sale of most oil from wells developed before 1979 under preexisting price controls than on newly discovered oil, heavy oil, and oil produced by certain enhanced recovery techniques. The presumption was that a high tax on the difference between the market price and the pre-1979 controlled price on the output from these wells would not significantly deter production because, once a well is developed, the cost of pumping oil is low compared to its price. However, there was still a tax, though at a lower rate, on newly discovered and high cost oil, and, as discussed previously, even the tax on old oil properties has some effect on supply.

Any overall analysis of the economic impact of the windfall profit tax must consider the effect on the economy if the revenues from the tax had not been available. While the tax has some adverse effects by deterring domestic oil production, higher budget deficits or higher levels of other taxes also can have adverse economic effects. An analysis comparing the windfall profit tax with higher levels of deficits and/or other taxes is not yet completed. We expect, however, that the tax caused some reduction in domestic oil supply, and therefore some increase in oil imports; however, since the tax did not significantly affect the price paid by consumers, its effect on conservation has been negligible.

With regard to the provisions of the tax that differentially affect independent producers, these provisions probably had very little overall effect on domestic oil production since they mostly apply to old oil, oil from stripper wells, and oil revenue from royalty interests. However, the phased reduction of the tax on new oil to 15 percent in the Economic Recovery Tax Act of 1981, did reduce an important production disincentive contained in the original windfall profit tax legislation.

REVENUE EFFECTS OF CERTAIN PROVISIONS IN THE TAXATION OF OIL AND GAS

[Dollars in millions]

| | Fiscal year— | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 |
| Tax expenditures: | | | | | | | | |
| Percentage depletion | −$1,865 | −$2,425 | −$1,955 | −$1,545 | −$1,465 | −$1,600 | −$1,660 | −$1,610 |
| Intangible drilling costs: | | | | | | | | |
| Compared to depletion using current law | −3,525 | −3,430 | −1,520 | −1,215 | −1,315 | −1,435 | −1,710 | −1,965 |
| Compared to separate cost depletion for all IDC's | −2,995 | −2,810 | −855 | −550 | −625 | −700 | −915 | −1,105 |
| Windfall profit tax provisions: | | | | | | | | |
| Independent's 1,000 BPD at reduced rates | −740 | −590 | −400 | −305 | −280 | −270 | −260 | −240 |
| Independent stripper exemption | | | −315 | −210 | −175 | −185 | −190 | −185 |
| Royalty owner exemption | | −675 | −310 | −210 | −245 | −235 | −220 | −190 |

Chairman **Rangel**. Mr. Secretary, who is preparing this study on the effects of decontrol?

Mr. **Ballentine**. There is an interagency working group.

Chairman **Rangel**. Who is in charge of it?

Mr. **Ballentine**. I believe the central group is at the White House. Essentially under the Cabinet Council on Natural Resources, I believe.

Chairman **Rangel**. Do you have any idea when the study will be available to Congress?

Mr. **Ballentine**. I believe it should be available within the next 2 or 3 months.

Chairman **Rangel**. Is the Treasury Department a part of the group?

Mr. **Ballentine**. Yes, Mr. Chairman, they are.

Chairman **Rangel**. Well, it certainly is something that we need. Did you give in your testimony the total amount of revenue lost as a result of the differences in tax treatment between the independents and the majors?

Mr. **Ballentine**. Yes, Mr. Chairman, I did. I believe I gave a figure of about $3 billion in 1983 that declines to a low of $2 billion throughout the rest of the time, primarily due to the oil prices.

Chairman **Rangel**. Do you have any ideas as how we could provide better or more uniform tax treatment and reach the same economic goals for the oil industry and for domestic production?

Do you think that the law, as we have it on the books now, is the best we can do, or should the law be more uniform?

Mr. **Ballentine**. We are not suggesting any changes at this time. Consequently, that essentially implies whatever gains in uniformity that could be made, and I think—there is a lack of uniformity—what gains in uniformity could be made are outweighed by the advantages that that lack of uniformity gives in encouraging a particular sector of this industry.

As a first presumption, uniformity in taxation is a goal, is a desirable goal. In this case there has been the argument made that special circumstances, additional risks, the wide variety of a few very large firms, and many very small firms in the industry override that general need and desirability of uniformity in tax treatment.

Chairman **Rangel**. When did the administration reach this decision?

It was my opinion that they were opposed to having different treatment for the independents and the majors, and that these provisions worked their way into ERTA for a lot of reasons which were not supported by the administration.

Mr. **Ballentine**. At that time, indeed, we preferred to see that bill not containing provisions like this early on. As you know, there were complex discussions going on, particularly through the latter stages of the bill.

Our position now is that we are not seeking repeal of any of the provisions, the oil provisions that were in ERTA, and consequently that is based upon the judgment that at that time, whatever gains might be achieved in uniformity, are outweighed by the effects they would have on a particular segment of the industry.

Chairman **Rangel**. So, the administration has reached this decision based on a policy of protecting our oil and gas industry, increasing domestic production, and encouraging competition. Because, if you change your mind, I just would want to know whether your decision today and your testimony today is based on the facts as relates to the oil and gas industry rather than other, more political considerations that were mentioned during the time that we were discussing ERTA.

Mr. **Ballentine**. Our conclusions now are based upon our understanding of the facts.

As I indicated in my testimony, I think the effects in several cases on entire domestic production could not be terribly large from these provisions. There would be some effects, but particularly with the 1,000-barrel limitation and such, most producers, the integrated and those above a thousand, would not be affected at the margin by these.

So, there is some reason, on the basis of domestic production and other reasons, on the basis of competitive equity otherwise, in the industry.

Chairman **Rangel**. So, even though we will be losing $3 billion a year, you think that is in the best interests of the industry and the country?

Mr. **Ballentine**. Yes, Mr. Chairman.

Chairman **Rangel**. Mr. Pickle.

Mr. **Pickle**. I thank the Chairman. With regard to tertiary and secondary recovery, the language was interpreted to mean after December 31, 1983, there would be no percentage depletion allowed for tertiary or secondary production.

I don't think that was the intent of the Congress. I think it was largely a technical error, and that we should do something about that between now and the date, so we have that corrected.

Do you agree that it should be corrected?

Mr. **Ballentine**. Yes, Mr. Pickle, that is our understanding too. It was basically a drafting problem.

Mr. **Pickle**. Now, when I read your testimony, on page 4, third paragraph, and again on page 6, you point out that since the enactment of the ERTA bill, the relative advantage provided to domestic production compared to other investors, has virtually disappeared.

In other words, because of the ERTA, ACRS deductions and the ITC are equally as appealing as any advantage you might get in the domestic oil industry, and therefore this is not an excessive incentive to the industry.

Am I interpreting your statement correctly?

Mr. **Ballentine**. Yes, Mr. Pickle, that is right.

The combined effect of the 3- and 5-year depreciation period, cost recovery period, and the investment tax credit at an interest rate of 10 percent, is essentially about the same as expensing.

Mr. **Pickle**. The oil and gas industry, even in the expensing area, is getting no more advantage or disadvantage than other industries.

Mr. **Ballentine**. With regard to expensing, as compared with 3- and 5-year property, that is correct.

Mr. **Pickle**. Do you take a position on depletion allowance?

Do you feel the percentage depletion should continue, or be available for independent producers?

Mr. **Ballentine**. We are not suggesting any changes in percentage depletion at this time, no.

Mr. **Pickle**. We are going from 27 percent down to 15 percent and Treasury would recommend no changes.

Mr. **Ballentine**. We are not recommending any further changes, no.

Mr. **Pickle**. Thank you.

Mr. Duncan.

Mr. **Duncan**. No questions, thank you.

Mr. **Pickle**. Mr. Dorgan?

Mr. **Dorgan**. Thank you, Mr. Chairman. Just a brief question.

Generally, among tax experts there is a view that there is tax consequence on the one hand, and behavior on the other hand, and that if you modify tax laws, you will encourage or discourage certain behavior.

In the tax code as it relates to the oil and gas industry, we have a number of so-called tax expenditures or provisions that attempt to encourage or discourage behavior.

In this case mostly encourage behavior. Some people have talked about trying to measure the efficiency of these tax expenditures. Do you have any information on the efficiency, that is, the effectiveness by which that tax provision would modify behavior of the IDC, percentage depletion, et cetera?

Do you have any notion about efficiency with respect to those expenditures?

Mr. **Ballentine**. We don't have any estimates on efficiency gains and losses from these provisions. I think we do have some notions—it is complicated. On the one hand, as we were just discussing, there is an argument to be made that by allowing expensing intangible drilling costs instead of recovering them over a much longer period of time, efficiency is gained because that is more close to the tax treatment of other depreciable assets.

With regard to different tax treatment of producers in essentially the same industry, as I said before, there is a kind of basic tax policy that at first there is an efficiency loss that occurs from a differential tax treatment.

That may be offset by other advantages in the industry, basically there are nontax reasons for competitive disadvantages in the industry—that what is apparently first an efficiency loss in providing unequal tax treatment for people doing the same thing, can instead have advantages, but quantitative estimates of those things are difficult. More of an analysis than that, I don't think we really have at this time.

Mr. **Dorgan**. Should there be a quantitative analysis? Has Treasury attempted to undertake an analysis of the efficiency of expenditures in the Tax Code?

I am not necessarily opposed to them. I guess my feeling is if revenue foregone is a so-called tax expenditure, maybe we ought to measure the efficiency of it.

I came here from the Agriculture Committee, as did Mr. Thomas, and we talked at length over there about what is the efficiency of this expenditure or that expenditure, the food stamp program or another program.

In the Tax Code we also, in effect, by foregoing revenue, have an expenditure program. And in almost every other case where I have asked the same question, there is no analysis of how efficient a tax expenditure is. Should Treasury be doing some expenditure analysis?

Mr. **Ballentine**. I think you are exactly right, and we do. We do pursue this.

In many cases, particularly in situations like this, the data is not available for some time in order to really pursue this very kind of issue.

That is always a frustration, but there is such an enormous lag because a lot of this is based on tax return information, that you do this promptly. Yes, Treasury is interested in it and remains professionally always interested in studying the effects of various tax provisions, be they called tax expenditures or whatever.

In this particular case we really don't have the data now yet to examine, for example, the change in output of independent producers who produce less than 1,000 barrels a year due to various provisions, and that is the question we would like to look at, as well as questions which are a little outside of our direct expertise, which is to say absent tax provisions, are there other monopoly type elements in the industry that would reduce the relative output of small producers beyond what would be efficient.

Mr. DORGAN. Does the Energy Department have any information on that? Have they done any study of efficiency?

Mr. BALLENTINE. They have done general studies on the effects of, say, oil prices on supply and such. I don't know of specific studies in this area, particularly data that divides the industry up into independents and integrated and small independents is very scarce.

Mr. DORGAN. The other day someone sent across my desk—I assume it was one of the integrated companies or the groups that represent them, some information. I did not bring it with me this morning.

It suggests—although there is provision in the law that has differing treatment for independents vis-a-vis integrated companies—that while the independents get preferable treatment, the integrated companies in fact produce most of the oil.

It appeared to me that they were trying to make the best case for the integrated companies. My sympathies, I guess, are more toward the independents, coming from where I come from, and watching, as I have, the development of oil and gas in North Dakota.

But, how do you respond to the proposition that the integrated companies think that if you have tax treatment that is more favorable to the independents, but in fact the production records don't show the independents to match our performance, is that accurate?

Mr. BALLENTINE. I am not sure I am the person to evaluate the performance statement, but it clearly indicates the integrates produce most of the oil, and if there were a single goal involved outside of issues about monopoly power and risk issues—a single goal involved which says maximize oil production, there would be considerable arguments that say that much of the benefit should go to the integrated.

Mr. DORGAN. Your point is well taken. There is not a single goal involved. We are interested in avoiding concentration that chokes markets and increases economic concentration. Our friend in the Justice Department has said that if America were comprised of 100 corporations, each doing 1 percent of the business, he would be satisfied and happy.

I think he doesn't understand what America is about. It is the opportunity for a lot of independent producers and independent businesses to do their thing and have an opportunity to make it. It is true in the oil industry as well.

I appreciate your response. Thank you.

Chairman RANGEL. Mr. Duncan.

Mr. DUNCAN. No questions, thank you, Mr. Chairman.

Chairman RANGEL. Mr. Anthony.

Mr. ANTHONY. Thank you, Mr. Chairman.

Mr. Ballentine, I apologize for being out of the room. I had another tax bill I wanted to introduce while we were in session today.

I would like to highlight a couple of things that you have in your prepared text.

Maybe I want to highlight them because you are one of the rare witnesses that comes before this committee who happens to stake out a position that I have publicly stated is my own.

On page 7 you talk about the exemption for stripper well production by independent producers and how it is intended to prevent premature abandonment of properties, and then you go on to say that the stripper wells are usually, but not always oil wells in the late stages of their productive life, and then you make the statement—and this is what I wanted to highlight:

"In the absence of the stripper well exemption, the windfall tax would cause some wells to be shut down that would otherwise continue to operate."

That is a point that we have been trying to make over and over again from a standpoint of good tax policymaking good energy policy. For every barrel of oil that these stripper wells produce, there's one less barrel we don't have to go to OPEC and buy, and that is helping our trade deficit.

Then over on page 8 you talk about the royalty owner and the need for some exemption in trying to help the low- and middle-income recipients to have royalty income. But you do go further to make this statement—I just wanted to highlight it for the record:

> However, in those cases where land has value and an alternative use, the royalty owner exemption could raise after-tax returns to a prospective producer by affecting the terms at which an owner is willing to allow oil development on his property, and believe me, I can tell you, and bring royalty owners in here that could prove that very point for you.
>
> As a matter of fact, people in my part of the country do have alternate uses of that land, principally growing timber and selling it for the timber value, and so in many cases those people don't even want the oil people in there to begin with because they sometimes get upset about the clearing of the land, the potential of damage from salt water * * *

So I can tell you in many cases where your statement has proven exactly correct, even from the tax that we have imposed as it stands. I wanted to highlight that for the record.

Thank you, Mr. Chairman.

Chairman **Rangel**. Mr. Thomas.

Mr. **Thomas**. Thank you, Mr. Chairman.

Mr. Ballentine, first of all I want to compliment you for your testimony.

On page 11 in the middle of the page, you say:

> The tax was designed to attempt to minimize the effects on domestic supply by applying a higher tax rate on the sale of most oil from wells developed before 1979 under preexisting price controls than on newly discovered oil, heavy oil, and oil produced by certain enhanced recovery techniques.

Do you have any information why in the previous administration they established heavy oil at an API gravity of 16 rather than the normal industry accepted level of 20?

Mr. **Ballentine**. I really don't. I don't know the history of that.

Mr. **Thomas**. I was told the reason that was selected was that using 16 obviously produces more revenue than picking 20.

Where are we on our estimates of revenue produced by the windfall profit tax since it was originally assumed versus what we are getting now?

Mr. BALLENTINE. We are showing it coming in considerably below what it was initially estimated, primarily because of the differences in oil prices from what they were estimated to be initially.

I don't believe we have estimates indicating how the initial estimates differed on the basis of sub groups, particularly heavy oil.

Mr. THOMAS. I also want to reinforce the gentleman from Arkansas' comments, that although it might seem incredulous to some, there are individuals out there who operate under the laws of economics, and that something as improbable as classifying heavy oil under windfall profits at 16 rather than 20 might be the economic incentive not to either bring in another well, produce it at a certain level, try to move it as a stripper rather than maintain production. Because the folks out there really do operate on whether or not the bottom line is a profit or a loss on a statement.

And it makes a difference as to whether they stay in business or not. I know when we talk about the amounts of revenue that we are going to generate, oftentimes we get a little carried away with our estimates, and therefore think, let's do more of it because we will get more money, but in the real world when you do so much you in fact wind up getting less because there are people out there who will not respond to our desire to get more taxes out of them.

They simply go out of business.

Is there any discussion that you are aware of on a reexamination of the Windfall Profit Tax Act in terms of the administratively classified level for heavy oil?

Mr. BALLENTINE. I am not aware of any.

Mr. THOMAS. I encourage you to examine it, since any of the estimates of revenue are so far off that you are not going to reach the magic number that people thought they were going to, and that if that is the case, we might actually produce a bit more oil if we used a generally accepted definition of heavy oil.

In addition, briefly, did you hear my comments in terms of the way the windfall profit tax has produced unintended consequences in terms of closing down some independent refineries, because they no longer produce the residual fuel oil to be burned in boilers and the tax you thought you were going to get from that barrel of oil that was going to leave the property you no longer get because that barrel of crude is being burned on the property?

Mr. BALLENTINE. Yes, I did hear your comments. It was mentioned to me you sent a letter recently to Secretary Chapoton on the issue, I believe.

Mr. THOMAS. I have a bill in also. The irony is, you don't get the tax you thought you were going to get for burning heavy crude, for Btus, higher pollution. It just doesn't make economic sense, environmental policy sense or tax sense.

Thank you, Mr. Chairman.

Chairman RANGEL. Mr. Campbell.

Mr. CAMPBELL. Thank you, Mr. Chairman.

Mr. Thomas covered one of the subjects I was interested in on what happened to the windfall profit tax with regard to categories, which you don't have here.

Do you have any figures that estimated the windfall profit tax percentage you would get from different categories?

Mr. BALLENTINE. I am not aware. Let me see.

We can get some information on the difference by tiers. I don't have it now. I could supply that for the record.

Mr. **Campbell.** My interest is that we determined, when the original estimate was made, what percentage of that original estimate came from certain categories.

Mr. **Ballentine.** You mean tier as opposed to size of producer.

Mr. **Campbell.** I would like to know tiers, and I would also like to know the percentage from the independents and from the majors.

Mr. **Ballentine.** I think we do not make estimates of the latter. However, much of these revenues would come from producers of less than a thousand.

Mr. **Campbell.** You had a different tax rate in there. Surely, there was some estimate as to the impact at that time of the tax rate and the differential?

Mr. **Ballentine.** That is right. There is an estimate in here, but it doesn't say how much—what there is is an estimate of how much oil is produced by independents, less than 1,000 but of those, how many of those are independents who had in total say only 800 barrels and an independent 1,600, 1,000 of which was exempt.

We don't know that distinction.

Mr. **Campbell.** I am interested to see how much falloff percentagewise, you had in each category from the original estimate.

Mr. **Ballentine.** Let me provide what we can for the record.

Mr. **Campbell.** The second thing that I would like to ask is, given the incentives that are in the law today, and given the great cost of capital, and the difficulty of small operations to raise capital, do you think we would have the exploration and the discovery we have among independents if we did away with these differentials?

Mr. **Ballentine.** Certainly, these differentials would have some effect on independent production; it would lower it. We don't know how much.

To the extent to which an independent is larger than 1,000 barrels, the exemption limited to 1,000 barrels would not affect their level of production, but certainly for the stripper well exemption and those independents less than 1,000 barrels, there would be an effect on the margin at their production, and repealing these provisions would lower it.

Mr. **Campbell.** So, it is safe to say for those producing under 1,000 stripper wells, we would be in a position of probably discouraging exploration among some groups and in effect discouraging the production of our own energy source in this country were we to do that. Is that a fair statement?

Mr. **Ballentine.** Relative to the tax laws now, that change would discourage some domestic production, yes.

Mr. **Campbell.** Thank you.

Mr. **Pickle.** Would the gentleman yield? I would like to also stress that point.

You said in your statement that our tax laws have an economic effect of providing different incentives for different types of producers—the majors, independents, large or small. That is the reason why we have these differentiations. If you don't do that, you lose a lot of production that otherwise would be so marginal that the majors or very large independents wouldn't fool with it.

We have to remember that. That is why that is being done, and I appreciate your statement on that. I am glad you asked that question.

Chairman **Rangel**. I appreciate your statement as well, Mr. Secretary, because I assume that the larger the tax expenditure, the more you need to find increased production which makes a lot of sense. The real problem is that you are saying you don't really know how much production is increased, but you know it is costing $3 billion a year.

Mr. **Ballentine**. Yes, Mr. Chairman.

Chairman **Rangel**. Any of us can ask any number of questions where your answer would be yes. For example, would you have increased production if the price of oil went up?

The answer is "Yes."

Would there be increased production by independents?

The answer is "Yes."

If we double the $3 billion incentive to make it $6 billion, would there be an increase in production?

The answer is "Yes."

But the truth of the matter is that you are still studying the impact of this preferential tax treatment for independents as opposed to majors.

I might say, has the administration changed its mind on the windfall profit tax at all? Do you think that tax should stay in place?

Mr. **Ballentine**. The President has said he thinks it was a bad tax. We are not proposing any changes now in the windfall profit tax, however.

Chairman **Rangel**. So, that is a bad tax, and the preferential treatment for independents, which at one time the President thought was a bad tax, is now a good tax policy.

Mr. **Ballentine**. We are not recommending any changes, recognizing the multiplicity of goals that are involved in the tax treatment of this industry.

Mr. **Pickle**. He didn't say the windfall was a good tax. He just indicated it was necessary.

Chairman **Rangel**. So, the difference between independents' tax treatment and majors' tax treatment is not necessarily a good tax policy, but considering the complexity of changing it, you are not recommending a change.

Mr. **Ballentine**. Considering the multiplicity of goals.

Chairman **Rangel**. Multiplicity of goals?

Mr. **Ballentine**. That is right.

Chairman **Rangel**. Is there any other industry that we want to protect, considering the multiplicity of goals? Any industry might recommend a different treatment in order to shore it up, increase production and make certain capital available for it?

Mr. **Ballentine**. We have not isolated any other area where we would make similar provisions.

Chairman **Rangel**. It is the unique nature of the oil industry, basically.

Mr. **Ballentine**. Yes, Mr. Chairman.

Mr. **Campbell**. Mr. Chairman, I had one more question.

Chairman **Rangel**. Mr. Campbell.

Mr. **Campbell**. Following that line through, and I agree with the chairman, you can ask a question in any manner and get any answer—I could ask if, having reduced the capital gains tax, it did not increase the revenue that came to the Treasury? You would answer yes to that, so, in fact, sometimes you can reduce taxes on people, encourage more economic activity, and increase revenue.

I am not going to ask that. I just wanted to make that point.

The fact is though that we are talking about the production of energy in this country.

Do you know what percentage of new discoveries are made by independents?

Mr. **Ballentine**. I don't have a good figure there. Like the number of new discoveries, the size of discovery, I would expect the independents have a high fraction of wells, but a relatively low fraction of output because they tend to deal in wells with smaller output.

Accordingly, I would expect a rather high fraction of discovered property, but a low fraction of discovered oil.

Mr. **Campbell**. I think your analysis is correct. They are a very high fraction of the discovery of new wells. They are encouraged to look, by the law, where it might not be economically feasible for larger companies to look. If we were to change the law, as I understood earlier, it might be a disincentive to continue. The incentives in the law have certainly contributed to keeping our oil prices down.

Is that a fair statement?

Mr. **Ballentine**. It would have some of that effect at the margin, yes, to some extent.

Mr. **Thomas**. Would the gentleman yield briefly?

Chairman **Rangel**. Thank you, Mr. Secretary, for your testimony.

The members will have the opportunity to send additional questions to you. The record will remain open. Thank you.

Mr. **Ballentine**. Thank you, Mr. Chairman.

[The following was subsequently received:]

DEPARTMENT OF THE TREASURY
WASHINGTON, D.C. 20220

ASSISTANT SECRETARY

JUL 27 1983

Dear Mr. Chairman:

Attached are responses to the additional questions you sent relating to my testimony on the taxation of producers of oil and gas before the Oversight Subcommittee. Due to the recent mid-session budget review and other pressing work, we have not been able to respond to all the request for numerical estimates as rapidly as we had hoped. We will, however, supply the additional data we have promised by the end of next week.

Sincerely,

J. Gregory Ballentine
Deputy Assistant Secretary
(Tax Analysis)

The Honorable
Charles B. Rangel
Chairman
Subcommittee on Oversight
Committee on Ways and Means
U.S. House of Representatives
Washington, D.C. 20515

Attachment

1. The Congressional Budget Office has submitted to the Subcommittee revenue estimates for a series of legislative options which would alter the current tax treatment of producers of oil and gas. A copy is attached for your review.

(a) Does the Treasury agree with the CBO's estimates?

(b) Are there any other legislative options that the Subcommittee might consider?

(c) With regard to the 1983 expiration of percentage depletion for secondary and tertiary production, what revenue impact would extension of the primary production rate to secondary and tertiary oil have on Federal revenues?

The Treasury Department agrees with the methodology used by the C.B.O. With the single exception of the estimate for percentage depletion, the Treasury estimates, shown in Table 1, differ from the C.B.O. estimates only because the Treasury estimates are based on more recent projections of future oil prices and on slightly different projections of oil production. The C.B.O. prices are based on January projections, while the Treasury estimates shown in Table 1 are based on projections updated in April, 1983. Because of the decline in oil prices that occurred in the first few months of 1983, the projected prices of oil and levels of domestic production were lower in April than they had been in January. These differences in projections are particularly important for the estimates of the revenue effect of changes in the windfall profit tax and in percentage depletion because both the windfall tax collected and the amount of percentage depletion deductions claimed vary directly with the price of oil.

The only other source of difference in the two sets of estimates occurs in calculating the gain from repealing percentage depletion. The Treasury Department assumes that

Table 1

Revenue Effects of Changing Tax Provisions for Oil and Gas Producers

Congressional Budget Office Options

($ billions)

| | Fiscal Years | | | | | Cumulative |
|---|---|---|---|---|---|---|
| | 1984 | 1985 | 1986 | 1987 | 1988 | 1984-1988 |
| Capitalize all IDC's: | | | | | | |
| Treasury estimate ........................ | 1.9 | 3.7 | 3.2 | 2.7 | 2.4 | 14.0 |
| CBO estimate ............................. | 2.1 | 3.6 | 3.3 | 3.2 | 3.1 | 15.3 |
| Amortize 15 percent of IDC's over 3 years: | | | | | | |
| Treasury estimate ........................ | 0.1 | 0.2 | 0.1 | 0.1 | * | 0.6 |
| CBO estimate ............................. | 0.1 | 0.1 | 0.1 | * | * | 0.4 |
| Eliminate stripper exemption for windfall profit tax (retain reduced rate): | | | | | | |
| Treasury estimate ........................ | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.9 |
| CBO estimate ............................. | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 1.1 |
| Eliminate all reduced tax rates for independents in windfall profit tax (no stripper exemption): | | | | | | |
| Treasury estimate ........................ | 0.4 | 0.5 | 0.5 | 0.5 | 0.4 | 2.2 |
| CBO estimate ............................. | 0.5 | 0.6 | 0.5 | 0.5 | 0.5 | 2.6 |
| Repeal percentage depletion: | | | | | | |
| Treasury estimate ........................ | 0.6 | 1.4 | 1.5 | 1.6 | 1.5 | 6.6 |
| CBO estimate ............................. | 0.9 | 1.7 | 1.9 | 2.0 | 2.2 | 8.7 |
| Repeal exemption for royalty holders: | | | | | | |
| Treasury estimate ........................ | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 1.1 |
| CBO estimate ............................. | 0.4 | 0.5 | 0.4 | 0.4 | 0.4 | 2.0 |
| Expense all IDC's: | | | | | | |
| Treasury estimate ........................ | -0.2 | -0.3 | -0.2 | -0.1 | -* | -0.7 |
| CBO estimate ............................. | -0.2 | -0.2 | -0.1 | -0.1 | -0.1 | -0.6 |
| Extend stripper exemption to all stripper: | | | | | | |
| Treasury estimate ........................ | -0.3 | -0.5 | -0.6 | -0.6 | -0.6 | -2.6 |
| CBO estimate ............................. | -0.7 | -0.9 | -0.9 | -0.9 | -0.9 | -4.3 |
| Impose oil import fee ($2.00 per barrel): | | | | | | |
| Treasury estimate ........................ | 3.0 | 4.3 | 4.5 | 4.5 | 4.8 | 21.1 |
| CBO estimate ............................. | 3.1 | 4.4 | 4.3 | 4.3 | 4.3 | 20.4 |

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*Less than $50 million.

percentage depletion for secondary and tertiary production is reduced to 15 percent on January 1, 1984, while the C.B.O. appears to assume continuation of percentage depletion for secondary and tertiary production at 22 percent in its baseline revenue forecast. This difference in baseline assumptions accounts for about $90 million in 1984, $140 million per year for 1985-1988, and about $650 million for the entire five year period 1984-1988, of the difference between the C.B.O. and Treasury estimates of the revenue gain from eliminating percentage depletion. In other words, the revenue impact of allowing percentage depletion for secondary and tertiary oil at the current 22 percent rate rather than 15 percent after 1983 is about $650 million over the next five years.

The Treasury Department is not recommending any other legislative options for the Subcommittee's consideration at this time.

Finally, Table 2 shows that allowance of the 15 percent depletion rate for secondary and tertiary production after 1983 reduces revenue by $1.5 billion over the years 1984-1988, compared to elimination of percentage depletion for secondary and tertiary production.

2. During the Subcommittee's hearing, it became apparent that the term independent producer is defined differently by various groups. For tax purposes, in the most recent year for which there is available data,

(a) how many independent producers are there?

(b) to what extent do they file as individuals, corporations or partnerships?

Table 2

## Percentage Depletion

## Effect on Receipts of Allowing Percentage Depletion at 15 Percent For Secondary and Tertiary Production

Effective January 1, 1984

($ billions)

| Fiscal Years | | | | |
|---|---|---|---|---|
| 1984 | 1985 | 1986 | 1987 | 1988 |
| -0.2 | -0.3 | -0.3 | -0.3 | -0.3 |

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(c) to what extent do independents filing as individuals have IDCs in excess of their net income from their oil and gas properties?

(d) to what extent do independents filing as individuals have IDCs in excess of their net income from their oil and gas properties?

The Treasury Department has no direct information on the number of independent producers from tax returns and is aware of no other statistical source that would enable us to determine the number of independents.

Under the tax law definition, taxpayers rather than enterprises are the unit for determining qualification as an independent producer. Thus, independent producers include corporations, individual taxpayers who operate one or more sole proprietorships in oil and gas production, and individual taxpayers who own shares of partnerships in the oil business.

There are data on the number of tax returns filed by corporations, partnerships, and sole proprietorships in the oil industry. These data suggest that the number of taxpayers who qualify as independent producers is large, but do not allow a very precise estimate because there is not a close correspondence between the number of returns filed and the number of producers.

The 1980 Statistics of Income show the following data on the number of returns:

| Corporations | All Returns | Returns With Net Income |
|---|---|---|
| Oil and gas extraction, other than oil field services | 6598 | 3170 |
| Petroleum refining (including integrated producers) | 260 | 142 |
| Partnerships | | |
| Oil and gas extraction partnerships | 31405 | 14278 |
| partners | 686341 | 381428 |
| Sole Proprietorships | | |
| Oil and Gas Extraction (number of businesses) | 85735 | 45894 |

The refining category for corporations includes those not classified as independent producers under the tax law -- probably about 100 of the larger refiners. In addition, the partnership category includes partnerships of corporations as well as partnerships of more than one sole proprietor who are engaged in joint ventures. Finally, partners may be in more than one partnership; because of this overlapping, the actual number of partners who are independent producers may be much less than the total number who report income from at least one partnership.

Finally, since we cannot identify the independent producers from data on number of returns filed, we are also unable to say how many have filed in any one of the categories above, or in several categories or combinations of categories.

Taxpayers are generally not required to identify separately cost and percentage depletion on tax returns; only depletion must usually be reported. The one exception is for taxpayers paying either the corporate minimum tax or the alternative minimum tax for individuals; these taxpayers must report the excess of percentage depletion over the cost basis.

For purposes of revenue projections, we estimate that about 12.5 percent of domestic oil and gas production is eligible for percentage depletion because it represents the first 1,000 barrels per day or less of the output of independent producers and another 16 percent because it represents the first 1,000 barrels per day of output attributable to royalty interests. Therefore, we estimate about 28.5 percent of domestic oil and gas production is eligible for percentage depletion.

Finally, we are currently compiling data from the 1980 SOI tapes on the extent to which independents filing as individuals have IDCs in excess of their net income from oil and gas properties and will supply this information to the Committee next week.

3. With regard to royalty owners, please provide information which will assist the Subcommittee in determining the characteristics (income class, age, etc.) of those receiving royalty owner tax benefits. Also, provide information reflecting distribution of the royalty owner tax credits claimed under prior law.

We are currently compiling data from the 1980 SOI tapes on the distribution of royalty owner tax benefits and will have a response prepared for the Committee next week.

4. Your testimony did not directly address the effect on production of the availability of percentage depletion to royalty owners.

(a) Does the fact that percentage depletion is available to royalty owners have any effect on production? If so, how much?

(b) What part of the revenue loss attributable to percentage depletion is the result of its use by royalty owners? How many royalty owners take percentage depletion?

(c) What are the characteristics of the royalty owners taking percentage depletion, i.e., how many at various levels of adjusted gross income (AGI) take percentage depletion and on how many barrels of oil per day? How many of the royalty owners taking percentage depletion are corporations?

The fact that percentage depletion is available to royalty owners may increase production to a small degree. We have no quantitative estimates of how much production is increased.

In many situations, incentives available to royalty owners, such as percentage depletion and the exemption from the windfall profit tax of 2 (and after 1984, 3) barrels per day of production, provide little or no incentive for additional production. In particular, in those cases where oil rights have already been leased, the recipient of royalty income is a passive recipient of shares of production, who is not deciding on either the amount and type of drilling or the rate of extraction from developed properties. In other cases, however, where land has value in an alternative use, the incentives available to royalty owners raise after-tax returns to oil developers, and thus stimulate production, by affecting the terms at which an owner is willing to allow oil development on his property.

Although the exact share of the revenue loss from percentage depletion varies from year to year, the estimated share attributable to royalty owners varies from about 55 percent to about 60 percent of the total.

Finally, since the IRS does not require that percentage and cost depletion be separately identified, except for taxpayers liable for the minimum tax, we have no information on the number of royalty owners claiming percentage depletion and no information that would indicate whether or not the distribution of income among royalty owners claiming percentage depletion differs from the distribution of income among all royalty owners.

5. What is the effect on production of the royalty owners' exemption from the windfall profit tax of two ( and after 1984 three) barrels of oil per day?

The royalty owners' exemption may increase domestic production to a small degree. We have no quantitative estimates of how much production is increased. For a discussion of how incentives to royalty owners would tend to increase domestic production, see the response to question 4a.

6. How are the anti-transfer rules contained in IRC Sec. 4988(h)(4) being enforced?

In general, the IRS would detect violations of the anti-transfer rules in the course of audits. We have no indication that there are any problems in enforcing the anti-transfer rules relating to IRC Sec. 4988(h)(4).

7. You mention in your testimony that non-uniform tax treatment in the oil industry is justified because of other nontax goals.

a) What are these non-tax goals?

b) Do we get more production of oil and gas as a result of these differences in tax incentives? If so, how much?

c) What evidence do we have that the oil and gas industry is monopolistic or that we need different tax treatment for competitive equity reasons?

d) Do the independent producers face unique business problems not encountered by other small businesses when it comes to raising capital?

In enacting these provisions, the intent of the Congress was to promote and maintain the diversity of firm size and structure in the oil industry that exists when there are both integrated and independent firms. In addition, the intent of the special provisions for royalty owners under the windfall profit tax was to relieve certain small business and moderate income royalty recipients from what was believed to be an onerous burden imposed by this extra tax.

If one were simply to repeal the special treatment of independent oil producers, there would be some reduction in domestic oil production. In contrast, if the special benefits available only to independents were extended to all domestic oil production, there would be an expansion of domestic production.

We do not regard the oil and gas industry to be monopolistic. Although eliminating the special benefits for independent producers would increase the share of domestic production accounted for by the largest firms, this would not necessarily create a monopolistic condition, in the sense that domestic producers would have the power to control market prices. Therefore, these special provisions are not necessarily justified on grounds of avoiding monopoly or maintaining a competitive industry. It is true, however, that the independent producers do most of the wildcatting and develop many of the smaller properties. This type of activity would decline if the special benefits for independent producers were scaled back.

Finally, we have no evidence that independent oil and gas producers have unique problems in raising capital not encountered by other small businesses.

8. On what basis should the tax code provisions which distinguish between various producers be evaluated:

(a) The amount of revenues lost measured against any consequent increase in production?

(b) The amount of revenue lost measured against the degree of increased competition within the industry?

(c) Other grounds?

If encouraging production were the primary objective, the most cost-effective way of achieving it would be to provide incentives on equal terms to all oil producers. On the other hand, to the extent there is an interest in increasing the share of output accounted for by smaller, non-integrated producers, selective subsidies are required to achieved that objective.

Moreover, in evaluating potential changes in current tax code provisions, one should recognize that many persons were encouraged either to establish oil companies or to invest in the oil business because of the availability of tax incentives. In many cases, these individuals did not themselves earn extraordinarily high profits because the value of the tax incentives was capitalized in the price of oil leases. In addition, the recent decline in oil prices has reduced the profitability of many smaller oil companies and in some cases resulted in business failures and bankruptcies. One should take into account the hardship that might be imposed on many individuals and small businesses from any efforts to eliminate these tax benefits at this time.

9. To what extent are changes in price more or less important than tax incentives with regard to industry investment and increased production of oil and gas?

The decision to develop an oil property will depend on the expected after-tax return on the investment. For any given property with a given expected probability of finding oil, a given expected annual quantity of oil production if oil were found, and a given expected cost of development and of lifting oil, the expected after-tax return depends on both the price of oil and on the taxation of sales and profits. Both increases in price and reduction in taxes will increases prospective after-tax returns, and therefore increase the likelihood that the property will be developed and that oil will be produced. For any given change in tax policy, one can estimate the offsetting change in price that would keep the incentive to develop an oil property unchanged.

While in principle both tax policy changes and price changes affect investment in oil and gas, the changes in the world price of oil in the past decade have been so large that they have dominated changes in tax policy. The effects of world oil price changes were partially suppressed by price controls in the 1970s, but once the price of oil had been decontrolled the stimulus to investment and production from higher prices was much greater than any adverse effects from increases in taxation of domestic oil production between 1975 and 1981. Similarly, the effect on the incentive to produce of the decline in the world oil price since 1982 has been much larger than the effect of changes in taxation of oil production enacted since 1981.

10. To what extent has percentage depletion caused independent producers or royalty owners to become subject to either the corporate or individual minimum tax provisions? How many independent producers are subject to either the individual or corporate minimum tax? Of these, how many are limited partners?

We are currently tallying data from Statistics of Income for 1980 and will have an answer for the Committee by next week.

11. How are the anti-transfer rules applicable to percentage depletion (IRC Sec. 613A(c)(9) being enforced?

In general, the IRS would detect violations of the anti-transfer rules in the course of audits. We have no indication that there are any problems in enforcing the anti-transfer rules applicable to percentage depletion.

12. What portion of the costs of drilling an oil and gas well is usually expensed as intangible drilling costs (IDCs)?

The portion of the costs of exploration and development of oil and gas wells accounted for by different types of expenditures varies greatly among properties. In particular, the costs of geological and geophysical surveys and of land and lease acquisition attributable to any property varies greatly among properties, depending on the cost and effort required to identify potential drilling sites and the market value of land in the particular area. Data from the Annual Survey of Oil and Gas, published by the U.S. Bureau of the Census, show that land and lease acquisition, geological and geophysical survey, and related expenditures accounted for roughly 25-30 percent of the costs of exploration and development of oil and gas wells over the period 1977-1981. These costs are capitalized and included in the taxpayer's basis for computing cost depletion deductions.

Of the remaining costs of drilling an oil and gas well, roughly 75-80 percent are expensed as intangible drilling costs, with the remaining 20-25 percent representing costs of capital equipment, most of which can be recovered according to rules for 5-year ACRS property. Thus, something on the order of 50 to 60 percent of all the pre-production costs of drilling oil and gas wells are normally expensed as intangible drilling costs. As I have noted, this is a very rough estimate. The actual percentage that is expensed as intangible drilling costs varies greatly among properties.

13. Does expensing IDCs increase the amount of drilling that is done? If so, how much and which types of drilling activities, i.e., exploratory or developmental?

The question of whether IDCs increase the amount of drilling cannot be answered without reference to what method of capital recovery would be required if intangible drilling costs were not to be expensed. If exploration and development expenses of oil and gas wells were subject to the same rules as 5-year ACRS property -- i.e., depreciable according to the schedule allowed for 5-year property and eligible for the investment credit -- the present value of tax savings from depreciation deductions and the investment credit would be approximately the same as the present value of tax savings from expensing. Therefore, if 5-year ACRS is the standard against which expensing of IDCs is compared, then IDCs do not encourage reallocation of capital from other types of machinery and equipment to exploration and development of oil and gas wells.

In contrast, if the alternative to expensing is regarded as capitalization of IDCs, with recovery by cost depletion over the presumed life of the property, then IDCs provide incentives that increase both exploratory and developmental drilling. In addition, for those producers currently allowed percentage depletion, and for whom percentage depletion deductions exceed the basis in property, the alternative to expensing of IDCs may be regarded to be no deduction at all for IDCs. In effect, the percentage depletion deductions based on the annual value of producing wells could be large enough over the life of a property to recover more than all costs of developmental drilling and of exploratory drilling on both successful and unsuccessful wells. In this case, IDCs can be viewed as providing a very large incentive for both exploratory and developmental drilling.

14. Intangible drilling costs of individuals and certain closely held corporations are subject to the "at risk" rules. Is there any need to extend the "at risk" rules to other corporations?

There is no need to extend the "at risk" rules to other corporations.

The "at risk" rules with respect to intangible drilling costs limits the amount that any individual or closely-held corporation can deduct with respect to intangible drilling costs for oil and gas wells to the amount of the investor's personal liability with respect to the investment. These rules have the effect of limiting the transfer of tax deductions to limited partners in an oil and gas partnership, thus limiting the extent to which deductibility of intangible drilling costs can be used as a tax shelter by investors in high tax brackets. Such investors can benefit from the tax advantages resulting from deductibility of intangible drilling costs only to the extent that they have placed at risk the funds they have expended, or are legally committed to expend, on the project.

There is no need to extend these provisions to other corporations because, except in the case of subchapter-S corporations, the tax benefits from corporate deductions of intangible drilling costs do not flow directly to individual investors, and thus cannot be used to offset other sources of income. Therefore, the transfer of tax deductions to corporations, other than some closely-held corporations, does not create additional opportunities for tax shelters for high-bracket individuals.

15. In FY 1982 the net receipts from the windfall profit tax were $8.4 billion or only 44 percent of the gross receipts of $18.8 billion. Why were the net receipts so much lower than the gross receipts in FY 1982? (In FY 1981, for example, the net receipts were $14.1 billion, about 61 percent of the gross receipts of $23.2 billion.)

Net liabilities from the windfall profit tax have remained a roughly constant share of gross liabilities, increasing from 52 percent in 1981 to 53 percent in 1982. In the long run, the ratio of net receipts to gross receipts will be approximately equal to the ratio of net liabilities to gross liabilities. In 1981 and 1982, however, the ratio of net to gross receipts was subject to considerable variation, rising to 61 percent in 1981 and then declining to 44 percent in 1982.

The decline in the ratio of net to gross receipts from the windfall profit tax between 1981 and 1982 resulted solely from differences in the timing of receipts, compared to liabilities, between excise taxes and income taxes. Both net and gross liabilities from the windfall profit tax declined between 1981 and 1982 because the fall in world oil prices lowered the base for the windfall tax. Receipts from the tax, however, declined more rapidly than the decline in offsetting income tax liabilities because excise taxes are collected relatively soon after they become due, compared to income taxes. The windfall profit tax is generally remitted relatively soon after the liability is incurred, while significant offsetting changes in income tax liabilities frequently cannot be anticipated in quarterly estimated income tax payments. The change in income tax receipts, instead, appears in final tax payments for the year.

Table 3 shows clearly the differences in the timing of receipts and liabilities. Between calendar years 1981 and 1982, gross liabilities from the windfall profit tax declined from

$25.9 billion to $16.6 billion. The associated income tax offset declined by the same proportion, from $11.1 billion to $6.7 billion. Between Fiscal years 1981 and 1982, windfall receipts fell from $23.2 billion to $18.8 billion, while the income tax offset actually increased from $7.8 billion to $9.2 billion, causing the ratio of net to gross receipts to decline. The growth in offsetting receipts (i.e., reduction in income tax collections) in Fiscal 1982 reflects with a time lag the increase in both excise tax liability and the related reduction in income tax liability in the previous calendar year.

16. Numerous witnesses suggested that the oil and gas production industry pays the highest (or an unusually high) rate of tax. Please comment.

(a) With regard to effective corporate rates, what rate of tax do the independent and the major corporate producers pay? (average rate, marginal rate, other?)

(b) What impact does the windfall profit tax have on these rates of taxation?

(c) How do the various tax rates compare to the taxation of other industries?

The effective tax rate is generally defined as the difference between the before-tax and after-tax rates of return on investment, expressed as a percentage of the before-tax rate of return. For any given statutory tax rate, the effective tax rate so defined depends on the degree to which economic income is included in the tax base, the amount of credits available for investment, and the level of any additional taxes on income, such as the add-on corporate minimum tax. The extent to which taxable income approximates economic income is particularly sensitive to the rules relating to the timing of allowable deductions to recover capital costs.

## Table 3
## April Update, 1983

## Windfall Profit Tax Liabilities and Receipts

($ millions)

| | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | **Calendar Year Liabilities** | | | | | |
| Gross windfall profit tax, total ....... | 9,913 1/ | 25,883 1/ | 16,611 1/ | 9,722 | 6,941 | 6,331 | 5,927 | 5,655 | 4,975 |
| Reduction in income taxes 2/ ........... | -4,418 | -11,132 | -6,743 | -3,723 | -2,573 | -2,317 | -2,133 | -2,007 | -1,702 |
| Net windfall profit tax liability ... | 5,495 1/ | 14,751 1/ | 9,868 1/ | 5,999 | 4,368 | 4,014 | 3,794 | 3,648 | 3,273 |
| Outlays (- denotes increase) 3/ ....... | -729 1/ | -1,176 1/ | -1,033 1/ | -899 | -803 | -828 | -866 | -906 | -845 |
| Net budget effect .................... | 4,766 | 13,575 | 8,835 | 5,100 | 3,565 | 3,186 | 2,928 | 2,742 | 2,328 |
| | | | | **Fiscal Year Receipts** | | | | | |
| Gross windfall profit tax, total before refunds ............................ | 6,246 | 23,273 | 18,881 | 12,310 | 7,282 | 6,446 | 6,071 | 5,762 | 5,226 |
| Refunds ................................ | — | -28 | -68 | -325 1/ | -29 | -26 | -24 | -23 | -21 |
| Gross windfall profit tax after refunds | 6,246 | 23,245 | 18,813 | 11,985 | 7,253 | 6,420 | 6,047 | 5,739 | 5,205 |
| Reduction in income taxes .............. | -1,726 | -7,850 | -9,243 | -5,372 | -3,168 | -2,452 | -2,229 | -2,072 | -1,861 |
| Net windfall profit tax receipts .... | 4,520 | 15,395 | 9,570 | 6,613 | 4,085 | 3,968 | 3,818 | 3,667 | 3,344 |
| Outlays (- denotes increase) .......... | -529 | -1,352 | -1,124 | -768 | -800 | -820 | -858 | -891 | -946 |
| Net budget effect ..................... | 3,991 | 14,043 | 8,446 | 5,845 | 3,285 | 3,148 | 2,960 | 2,776 | 2,398 |

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1/ Includes the effect of the reduction in tax on oil from the Naval Petroleum Reserve under the Technical Corrections Act of 1982.

2/ Reduction in income taxes due to the deductibility of the windfall profit tax and income tax credits attributable to overpaid, windfall profit taxes.

3/ The windfall profit taxes attributable to economic interests of the United States Government, which reduce proprietary receipts and thus increase outlays.

The measurement of effective tax rates on oil production is further complicated by the presence of a special excise tax unique to the oil industry, the crude oil windfall profit tax. The windfall profit tax is not itself a tax on the return to suppliers of equity capital and therefore is not directly comparable to the corporate income tax. In order to include the effect of the windfall profit tax in any computation of the effective tax rate on the return to oil investments, one must assume that the ratio of capital to output in oil production is fixed. Under that assumption, any tax on oil output can be translated into an equivalent tax on the return to capital.

The effective tax rate measure so described can be used as an indicator of how the tax system discourages investment in oil, either compared to a world with no taxes on income from investment, compared to a world in which the effective tax rate is equal to the statutory rate (46 percent, at the margin, for most corporate income), or compared to a world in which the effective tax rate is equal to some weighted average of the tax rates applied to corporate investment in other sectors of the economy.

Unfortunately, as I indicated in my testimony, no one number can adequately summarize the effective tax rates on oil investments, because the rates vary greatly with characteristics of the oil property and type of investment. Effective tax rates vary among types of oil investments for two reasons. First, the different types of capital costs are subject to different recovery rules. Intangible drilling and development costs, including costs of drilling dry holes, may be expensed (other than the 15 percent that must be capitalized and then recovered over 36 months by integrated producers), while costs of geographic and geological surveys intended to locate new oil fields and costs of land acquistion must be capitalized and then recovered through cost depletion over the life of the property. In the case of independent producers allowed to use percentage depletion, any potential cost depletion deductions must be foregone if percentage depletion is used for a property, while use of percentage depletion does not reduce deductions on investments that may be expensed. As a result, effective tax rates are much lower for both independent and major corporations on properties where the ratio of dry holes to producing wells is high (because dry holes can be expensed) and much higher on properties where the potential for finding oil is high and is capitalized in the form of higher land or lease acquisition costs.

Second, the windfall profit tax rates also differ significantly by type of investment. The contribution of the windfall profit tax to the total effective tax rate on prospective oil investments is relatively low for investments in developing new oil properties and producing more oil from old properties using certain enhanced recovery techniques and is relatively high for some other investments intended to increase output from older properties.

My staff is currently preparing estimates of effective tax rates for investment in two types of new oil properties -- properties for which the probability of finding oil is so low that the cost of obtaining drilling rights is negligible and, at the other extreme, property on which oil is known to exist and on which the producer has to bid for the right to develop the oil. We will have these estimates available for the Committee next week.

17. One of the witnesses at our hearing, Dillard Spriggs, head of an economic consulting firm in New York called Petroleum analysis Ltd., testified that for every dollar spent by a major integrated company, 12 barrels of oil reserves (including gas

reserves in oil equivalent) were found. Do you agree with this estimate? What, if any, correlation is there between the dollars spent and the oil or gas produced or discovered by integrated companies? by independent producers?

In his testimony, Mr. Spriggs states that integrated companies discover about 0.12 barrels of oil reserves (including gas equivalent reserves) per dollar spent, not 12 barrels per dollar as the question states. This would imply an average finding cost of about $8.33 per barrel of reserves. He also presents data that show that the finding and development costs for the 20 leading companies in 1982 was $13.84 per dollar.

The Treasury Department has no independent estimates of either the average or marginal costs of finding and developing a barrel of oil. We have no reason to dispute the figures supplied by Mr. Spriggs.

18. Mr. Spriggs also stated that eighteen integrated companies reinvested 63 percent of their oil and gas revenues in exploring and developing oil and gas. What is the rate of reinvestment for independent producers as compared to integrated producers?

The Treasury Department has no data on the rate of reinvestment of profits or net cash flow by independent producers. We believe that independent corporate producers probably have very low dividend-payout rates, and also are generally not involved in other business activities, so it might be presumed that they invest much more than 63 percent of net profits in exploration, production, and development of crude oil and natural gas. For independent non-corporate producers, however, the question of what share of profits is reinvested is difficult to estimate even in a rough way. Many of these non-corporate producers are limited partnerships with many limited partners. In this case, a large portion of the net cash flow is returned to the individual investors, rather than to the entity itself. Whether these investors choose to reinvest their earnings from the partnership in the same venture, or whether they make some other use of their returns, requiring the entity to raise additional capital from new limited partners, cannot be determined and is probably irrelevant. What matters for determining the incentive to develop oil and gas properties is the prospective after-tax return available to potential investors, not which individuals invest in the activity.

19. Mr. Fred Hickman, former Assistant Secretary of the Treasury for Tax Policy, stated that the original windfall profit tax which Treasury proposed in 1973 was designed to be eliminated by now. Is this correct? Please explain.

The Treasury Department developed a windfall profit tax in late 1973 that was proposed to Congress by the Nixon Administration in January, 1974. The tax would have been imposed on the difference between the market price of oil and a legislated base price. Under the Administration proposal introduced at that time, it was intended that the tax be eliminated within 3-5 years. The elimination of the tax was to be accomplished by increasing the base price rapidly, at a proposed rate of about 1.5 percent per month. It was presumed that at this rate of increase the base price would eventually exceed the market price, thereby eliminating the tax.

In fact, at the proposed rate of increase over the initial base price, there would still be a windfall profit tax as of early 1983 under the Nixon Administration proposal because the price of oil, especially in 1979, increased more rapidly than was then anticipated. It is true, however, that the intention was to phase out the tax within a short period.

20. Mr. Hickman also tried to equate the loss of the tax benefits to an equivalent drop in the price of oil. He stated that the loss of tax benefits would be equivalent to a drop in

price of between $6 and $12. Do you think this is accurate? If not, what do you think the appropriate figure is?

Our calculations indicate that removing the special tax benefits available only to independents for a marginal new oil property that has just been acquired would be equivalent in its effect on the value of the property to a reduction in the world price of between $3 and $4 per barrel. For older oil properties on which independent producers also benefit from the special rates under the windfall profit tax, the loss in value would be greater than for new properties. The loss in value would be especially large for independent producers operating stripper wells. Therefore, on average, the estimates supplied by Mr. Hickman seem to be accurate.

Additional Material Requested by Congressman Carroll Campbell Jr.

1. When the tax was originally passed in 1980, what were the projected revenue estimates broken down by tier and by the class of producer (i.e., independent, integrated or royalty owners)?

We are unable to respond to this question directly because the detailed worksheets used in preparing the original estimates are no longer in the Treasury files or available on the Treasury computer. Because we were not required to submit such estimates in 1980, there would be no reason for us to have a record of them, except for what might be reconstructed from worksheets. Therefore, we cannot reproduce the details of the original estimates as requested. Table 4 does show the original revenue estimates computed by the Joint Committee on Taxation in 1980 and compares them to the current Treasury revenue estimates. The Treasury concurred with the 1980 Joint Committee estimates.

Both sets of estimates reported in Table 4 show the net budget effect; that is, the increase in windfall profit tax receipts less offsetting reductions in income tax receipts and offsetting outlays. The figures labelled "current estimate" are from the April, 1983 update of the budget. Following standard budget practice, these estimates are only for a five year period, through 1988. The 1989 and 1990 liabilities are assumed to equal the 1988 estimate in order to allow a comparison with the 10-year total revenue reported in the 1980 Joint Committee estimate.

2. How do these projections compare with the actual revenue raised, again broken down by tier and class of producer?

While we are unable to make a comparison of originally projected to actual revenue by tier, for the reasons cited in the response to question #1, we can explain why actual revenue and currently projected revenue is so much lower than the amount of revenue projected in 1980. The revenue from the windfall profit tax is smaller than originally projected because of 1) a decline in current and projected world oil prices, 2) a decline in projected domestic oil production, and 3) legislative changes that reduced the tax, including the exemption of 3 barrels per day of output of royalty owners, the reduction in the tax rate on new oil, and the exemption of stripper oil produced by independent producers.

Table 5 provides a rough breakdown of the sources of difference between the original and current estimates of calendar year windfall profit tax liabilities. The breakdown between the effect of lower oil prices and lower oil production is somewhat ambiguous because it depends on the order of computation. In preparing the table, we attributed to changes in production the reduction in revenue that occurred because production was lower, at the original, higher projected prices, and attributed to changes in prices the reduction in revenue that occurred because of lower prices, at currently projected rates of production. Had we reversed the order of calculation, computing the effect of the price change at the original projected level of production, and the effect of the production change at current prices, we would

### Table 4

### Original and Current Estimates of Net Windfall Profit Tax Liabilities and Receipts

($ millions)

| | Years | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | Total 1980-1990 |
| | | | | | | | **Original Estimate — Joint Tax Committee 1/** | | | | | | |
| Calendar year liabilities ... | 36 2/ | 6,306 | 14,719 | 18,875 | 20,147 | 21,312 | 22,267 | 22,907 | 23,778 | 24,588 | 25,771 | 27,017 | 227,723 |
| Fiscal year receipts ...... | — | 3,172 | 13,436 | 19,543 | 19,958 | 21,144 | 22,227 | 22,776 | 23,601 | 24,423 | 25,593 | 26,772 | 222,646 |
| | | | | | | | **Current Estimate -- Treasury Department 3/** | | | | | | |
| Calendar year liabilities ... | — | 4,766 | 13,375 | 8,835 | 5,100 | 3,565 | 3,186 | 2,928 | 2,742 | 2,328 | 4/ | 4/ | 51,661 5/ |
| Fiscal year receipts ...... | — | 3,991 | 14,043 | 8,446 | 5,845 | 3,285 | 3,148 | 2,960 | 2,776 | 2,398 | 4/ | 4/ | 51,548 5/ |
| Change in liabilities ... | -36 | -1,540 | -1,144 | -10,040 | -15,047 | -17,747 | -19,081 | -19,979 | -21,036 | -22,260 | 4/ | 4/ | |

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1/ General Explanation of the Crude Oil Windfall Profit Tax Act of 1980; (Joint Committee on Taxation, 1981).

2/ The Committee assumed that the prospective tax on newly discovered oil had reduced drilling, and thereby intangible drilling deductions, in 1979.

3/ April Budget Update, 1983.

4/ Not estimated for budget.

5/ Assumes constant liabilities in 1989 and 1990 equal to those in 1988.

have attributed more of the revenue effect to the price change and less to the production change. The sum of the price and production effects, however, is independent of the order of calculation.

As can be seen in Table 5, most of the difference between the original and current revenue estimates is due to differences in assumed levels of oil production and prices. Of the two, the change in prices accounts for at least twice as much of the revenue changes as the change in projected domestic production. Legislative changes included in the Omnibus Reconciliation Act of 1980, the Economic Recovery Tax Act of 1981, the Tax Equity and Fiscal Responsibility Act of 1982, and the Technical Corrections Act of 1982 account for only about $0.5 billion per year of the difference in revenue estimates.

The remaining technical reestimates account for between $1 billion and $3 billion per year of the difference in revenue projections. Of this figure, about $0.5 billion per year to $1.0 billion per year in the early 1980s results from reestimation of the effect of the net income limitation in the original Act. As noted in Table 5, it was also necessary to make a number of approximations in constructing the table, and the remaining difference attributable to these approximations is included in the line labelled "technical reestimates and errors."

As far as we know, both the original estimates and the current estimates were computed using the same assumptions about the distribution of oil production among tiers and types of producers. We have no reason to believe that our original assumptions about the shares of production in each tier owned by different producers were a source of significant error in past revenue projections, nor do we have information to suggest that the assumed shares should be revised at this time.

Moreover, changes in oil prices and total production -- the sources of most of the difference between the original and current estimates -- should not for the most part have had a significantly different effect by type of producer within each tier. The one exception, where a change in price would affect the share of revenue by producer classification, is for Alaskan north slope oil. This oil is produced almost exclusively by integrated oil companies and is classified as tier 1. Because of the high transportation cost of North Slope oil, the price received by producers, and thus the windfall profit tax base, is smaller than for other oil. As a consequence, any given absolute reduction in the world oil price will have a larger proportional reduction in the tax base for North Slope oil than for other categories of oil and will therefore cause some reduction in the share of revenue attributable to tier 1 production by integrated producers.

Legislative changes since the enactment of the Crude Oil Windfall Profit Tax Act, especially the provisions in the Economic Recovery Tax Act of 1981 and the Omnibus Reconciliation Act of 1980, have reduced the net liabilities of royalty owners and independent producers, relative to integrated producers. An estimate of the effects of the major items of legislation is provided in Table 6.

3. In the most recent estimates for 1983-1987, what are the revenue projections for each tier and each type of producer?

We are currently calculating the revenue effect by tier and type of producer, based on April budget assumptions, and will have an estimate available to the Committee next week. These estimates are not normally prepared for the budget process and therefore will take some additional time to compute.

## Table 5

## Sources of Change in Estimated Net Windfall Profit Tax Liabilities from Original to April Update

($ billions)

| | Years | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 |
| Incomes: | | | | | | | | | |
| Oil production | -0.3 | -1.2 | -1.7 | -2.4 | -3.1 | -4.4 | -5.3 | -6.3 | -7.7 |
| Oil prices | 0.4 | 1.4 | -4.6 | -9.3 | -11.5 | -13.0 | -13.3 | -14.8 | -15.2 |
| Total incomes | 0.1 | 0.2 | -6.3 | -11.7 | -14.6 | -17.4 | -18.6 | -21.1 | -22.9 |
| Legislation | -0.1 | -0.3 | -0.5 | -0.6 | -0.5 | -0.6 | -0.6 | -0.6 | -0.5 |
| Technical reestimates and error 1/ | -1.5 | -1.0 | -3.2 | -2.7 | -2.6 | -1.1 | -0.8 | -0.7 | 1.1 |
| Total change | -1.5 | -1.1 | -10.0 | -15.0 | -17.7 | -19.1 | -20.0 | -21.0 | -22.3 |
| Memo — Assumptions: | | | | | | | | | |
| Oil production (MMBD): | | | | | | | | | |
| Original | 9.0 | 9.1 | 9.3 | 9.5 | 9.8 | 10.1 | 10.3 | 10.4 | 10.6 |
| Current | 8.6 | 8.4 | 8.4 | 8.4 | 8.4 | 8.1 | 7.9 | 7.6 | 7.3 |
| Oil prices (dollars per barrel 2/): | | | | | | | | | |
| Original 3/ | 22.37 | 31.60 | 37.79 | 41.40 | 45.19 | 49.13 | 53.22 | 57.55 | 62.21 |
| Current | 24.23 | 34.33 | 31.22 | 28.06 | 27.53 | 29.17 | 31.06 | 32.96 | 34.51 |

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1/ This item includes technical reestimates as well as errors that may have occurred in constructing this table due to the need for approximation, see footnote 3, for example.

2/ Refiners aquisition cost for domestic oil.

3/ The original estimates, made during the period of oil price controls, were based on an assumed price for uncontrolled non-Alaskan oil with API gravity less than 16°. For comparability this has been converted to a domestic RAC, but the conversion is only approximate.

### Table 6

### Effect of Enacted Legislation on Net Windfall Profit Tax Liabilities by Tier and Type of Producer

April Update Assumptions

($ millions)

| | Years | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 |
| **Omnibus Reconciliation Act of 1980:** | | | | | | | | | |
| Royalty owners credit: | | | | | | | | | |
| Tier 1 | -64 | — | — | — | — | — | — | — | — |
| Tier 2 | -21 | — | — | — | — | — | — | — | — |
| Tier 3 | -25 | — | — | — | — | — | — | — | — |
| **Economic Recovery Tax Act:** | | | | | | | | | |
| Royalty owners credit and exemptions: | | | | | | | | | |
| Tier 1 | — | -169 | -219 | -129 | -88 | -83 | -64 | -50 | -36 |
| Tier 2 | — | -54 | -77 | -50 | -38 | -42 | -37 | -34 | -29 |
| Tier 3 | — | -68 | -128 | -109 | -99 | -126 | -130 | -130 | -119 |
| Reduction of tax on newly discovered oil: | | | | | | | | | |
| Tier 3 — Integrated | — | — | -29 | -30 | -23 | -30 | -47 | -52 | -28 |
| Independent | — | — | -10 | -11 | -8 | -11 | -17 | -17 | -10 |
| Royalty | — | — | -7 | -8 | -6 | -7 | -12 | -7 | -7 |
| Exemption for stripper oil produced by independent producers: | | | | | | | | | |
| Tier 2 — Independent | — | — | — | -237 | -179 | -181 | -186 | -191 | -183 |
| Exemption for certain charities: | | | | | | | | | |
| Unassignable by tier | — | -10 | -10 | -10 | -10 | -10 | -10 | -10 | -10 |
| **Tax Equity and Fiscal Responsibility Act:** | | | | | | | | | |
| Elimination of tax adjustment: | | | | | | | | | |
| Tier 1 Alaska — integrated | — | — | 97 | 0 | 24 | 24 | 24 | 24 | 24 |

### Effect of Enacted Legislation on Net Windfall Profit Tax Liabilities by Tier and Type of Producer

($ millions)

| | Years | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 |
| **Technical Corrections Act of 1982:** | | | | | | | | | |
| Reclassification of NPR 1/ | — | — | — | -- | — | -- | — | — | -- |
| Trust beneficiaries -- royalty owner: | | | | | | | | | |
| Tier 1 | — | — | -31 | -19 | -12 | -7 | -5 | -4 | -3 |
| Tier 2 | — | — | -11 | -7 | -4 | -4 | -3 | -3 | -2 |
| Tier 3 | — | — | -18 | -11 | -9 | -11 | -11 | -11 | -10 |
| By Tier and Type of Producer: | | | | | | | | | |
| Tier 1 — Alaska -- integrated | — | — | — | 97 | 0 | 24 | 24 | 24 | 24 |
| Tier 1 — Non-Alaska -- royalty owners | -64 | -169 | -250 | -148 | -100 | -90 | -69 | -54 | -39 |
| Tier 2 — Independent | — | — | — | -237 | -179 | -181 | -186 | -191 | -183 |
| — Royalty owners | -21 | -54 | -88 | -57 | -42 | -46 | -40 | -37 | -31 |
| Tier 3 -- New oil: | | | | | | | | | |
| Integrated | — | — | -29 | -30 | -23 | -30 | -47 | -52 | -28 |
| Independent | — | — | -10 | -11 | -8 | -11 | -17 | -17 | -10 |
| Royalty owners | -25 | -68 | -153 | -128 | -114 | -144 | -153 | -148 | -136 |
| Unassignable | — | -10 | -10 | -10 | -10 | -10 | -10 | -10 | -10 |

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1/ No effect on net liabilities.

DEPARTMENT OF THE TREASURY
WASHINGTON, D.C. 20220

DEPUTY ASSISTANT SECRETARY

RECEIVED
OCT 1 : 1983
Ways and Means
Subcommittee on Oversight

OCT 5 1983

Dear Mr. Chairman:

The enclosed submission provides further data, along with explanation of the data, relating to the testimony of J. Gregory Ballentine before the Subcommittee on Oversight, Committee on Ways and Means, May 5, 1983, on the taxation of oil and gas producers. This further data had been promised in a letter to the Subcommittee from Mr. Ballentine, dated July 27, 1983, that accompanied Treasury responses to follow-up questions from the Subcommittee on the May 5 testimony.

Sincerely,

(signed) Ronald A. Pearlman

Ronald Pearlman
Deputy Assistant Secretary
(Tax Policy)

The Honorable
Charles B. Rangel
Chairman
Subcommittee on Oversight
Committee on Ways and Means
U.S. House of Representatives
Washington, D.C. 20515

Enclosure

Additional Responses for Oversight Subcommittee

2d. To what extent do independents filing as individuals have IDCs in excess of their net income from their oil and gas properties?

The Treasury has data on excess IDCs only to the extent they were formerly reported for purposes of computing the add-on minimum tax. The last year for which data are currently available is 1980. In the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA), the add-on minimum tax was repealed and the alternative minimum tax was broadened. As a result of this change, such data will be available after tax year 1982 only for taxpayers who are subject to the alternative minimum tax.

Prior to TEFRA, taxpayers were required to file the form for reporting the add-on minimum tax only if 1) total tax preferences were more than $10,000 ($5,000 if married filing a separate return), even if there were no add-on minimum tax, or 2) minimum tax liability had been deferred from an earlier year. In the case of deferred minimum tax liability, however, it is unlikely that preference items for the current year would be reported unless total tax preferences in 1980 were also greater than $10,000.

Because of the $10,000 floor on reporting total tax preference items, data on excess IDCs were not available for taxpayers having small amounts of excess IDCs unless those taxpayers also had enough other preferences (in particular, percentage depletion) to make the total exceed $10,000.

Table 1 shows the distribution of excess IDCs claimed by individuals subject to the minimum tax, by income class, for 1980. As can be seen from the table, excess IDCs claimed by these individuals totalled $2.1 million in 1980, of which over 70 percent were claimed by individuals with AGI greater than $50,000 and about 30 percent by individuals with AGI greater than $200,000.

3. With regard to royalty owners, please provide information which will assist the Subcommittee in determining the characteristics (income class, age, etc.) of those receiving royalty owner tax benefits. Also, provide information reflecting the distribution of the royalty owner tax credits claimed under prior law.

Tables 2A and 2B report, respectively, the amount of net royalty income and the number of returns showing royalty income in 1980 individual returns. The data are tabulated by AGI class, type of filer, and presence or absence of the exemption for the aged. It should be emphasized that these data include other royalty income in addition to that from oil and gas. Separate data on oil and gas royalties are not available. In addition, the data are for net royalty income, where percentage depletion provides the major offset to gross royalty income. Finally, the data do not include royalty income of those not required to file.

Tables 3A and 3B report, respectively, the amount of qualified royalty credit claimed and the number of returns claiming the royalty credit, also tabulated by AGI class, type of filer, and presence or absence of the exemption for the aged. In 1980, the last year for which data were available, the credit was available to offset up to $1,000 of windfall profit tax liability to royalty owners who were individuals, estates, or qualified family farm corporations. This credit, enacted as part of the Omnibus Reconciliation Act of 1980, could be taken either in the form of windfall profit tax withholding or as a reduction in income tax liability. Because the provision allowing the credit was enacted near the end of 1980, it is likely that credits claimed in 1980 were entirely in the form of reductions in

### Table 1

### Individuals Subject to the Minimum Tax Claiming Intangible Drilling Costs in Excess of Their Income from Oil and Gas Properties

(Unpublished Tabulation, 1980 Individual Statistics of Income)

| Adjusted gross income class | Number of returns | Percent distribution | Dollar amount | Percent distribution | Average IDCs per return for returns having IDCs |
|---|---|---|---|---|---|
| | | (percent) | ($thousands) | (percent) | (dollars) |
| Less than 0 | 2,299 | 3.0% | $171,586 | 8.0% | $74,635 |
| $ 0 - $5,000 | 267 | 0.3 | 14,381 | 0.7 | 53,861 |
| 5,000 - 10,000 | 288 | 0.4 | 5,293 | 0.2 | 18,378 |
| 10,000 - 15,000 | 2,377 | 3.1 | 65,116 | 3.1 | 27,394 |
| 15,000 - 20,000 | 4,565 | 5.9 | 79,977 | 3.7 | 17,520 |
| 20,000 - 30,000 | 4,423 | 5.7 | 63,749 | 3.0 | 14,413 |
| 30,000 - 50,000 | 10,312 | 13.3 | 191,655 | 9.0 | 18,586 |
| 50,000 - 100,000 | 22,302 | 28.7 | 477,462 | 22.4 | 21,409 |
| 100,000 - 200,000 | 17,877 | 23.0 | 429,479 | 20.1 | 24,024 |
| Greater than $200,000 | 13,003 | 16.7 | 635,481 | 29.8 | 48,872 |
| Total | 77,713 | 100.0% | $2,134,179 | 100.0% | $27,462 |
| Total 1980 returns | 93,902,467 | | | | |
| Percent of 1980 returns having minimum tax — IDCs (percent) | 0.08% | | | | |

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Note: Details may not add to totals due to rounding.

individual income taxes. The royalty owner credit was expanded in the Economic Recovery Tax Act of 1981. Data for tax years after 1980, however, are not available at this time.

Corporations also receive royalty income and are allowed to claim percentage depletion as royalty owners. Table 4 shows, for 1980, the number of corporate taxpayers in the oil and gas industry who received gross royalties and who claimed percentage depletion as a preference item under the corporate minimum tax, together with the amount of percentage depletion claimed for that purpose. It should be noted that percentage depletion is only a preference item to the extent that the amount claimed exceeds the adjusted basis at the beginning of the tax year and also that the corporate minimum tax only applied to tax preferences in excess of $10,000 or the full amount of the taxpayer's income tax, whichever was greater.

4c. What are the characteristics of royalty owners taking percentage depletion, i.e., how many at various levels of adjusted gross income (AGI) take percentage depletion and on how many barrels of oil per day? How many of the royalty owners taking percentage depletion are corporations?

The Treasury Department does not have complete data on percentage depletion claimed in past years because only those individuals and corporations who were subject to the add-on minimum tax on tax preferences are available. Further, because the add-on minimum tax previously in effect for individuals, and still in effect for corporations, was applied only to percentage depletion in excess of adjusted basis, there was no requirement that percentage depletion deductions up to adjusted basis be reported separately on tax returns.

## Table 2-A

### Net Royalty Income Reported by Adjusted Gross Income Class, Type of Filer, and Age Exemption

(Unpublished Tabulation, 1980 Individual Statistics of Income)

(thousands of dollars)

| Adjusted gross income class | Single returns |  | Joint returns 1/ |  | Total returns |  |  |
|---|---|---|---|---|---|---|---|
|  | Aged | Nonaged | Aged | Nonaged | Aged | Nonaged | Total |
| ($000) |  |  |  |  |  |  |  |
| Less than 0 | 4,462 | 23,892 | 14,730 | 69,928 | 19,192 | 93,821 | 113,013 |
| 0 - 5 | 5,043 | 55,755 | 13,976 | 16,864 | 19,019 | 72,619 | 91,638 |
| 5 - 10 | 34,564 | 8,153 | 28,792 | 55,521 | 63,356 | 63,675 | 127,031 |
| 10 - 15 | 59,983 | 32,733 | 25,896 | 54,267 | 85,878 | 86,999 | 172,877 |
| 15 - 20 | 60,936 | 4,186 | 15,363 | 54,699 | 76,299 | 58,885 | 135,184 |
| 20 - 30 | 63,319 | 37,312 | 199,982 | 183,598 | 263,300 | 220,910 | 484,210 |
| 30 - 50 | 124,440 | 24,187 | 245,850 | 290,223 | 370,291 | 314,410 | 684,701 |
| 50 - 100 | 116,298 | 86,785 | 163,888 | 479,087 | 280,185 | 565,873 | 846,058 |
| 100 - 200 | 75,663 | 38,100 | 186,710 | 305,441 | 262,373 | 343,541 | 605,915 |
| 200 and over | 153,699 | 96,176 | 289,966 | 412,709 | 443,665 | 508,886 | 952,551 |
| Total | 698,406 | 407,282 | 1,185,154 | 1,922,336 | 1,883,560 | 2,329,618 | 4,213,178 |

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Note: Details may not add to totals due to rounding.

1/ Also includes married filing separately and head-of-household returns.

### Table 2-B

### Number of Returns Reporting Net Royalty Income by Adjusted Gross Income Class Type of Filer, and Aged Exemption

(Unpublished Tabulation, 1980 Individual Statistics of Income)

(thousands of dollars)

| Adjusted gross income class ($000) | Single returns | | Joint returns 1/ | | Total returns | | |
|---|---|---|---|---|---|---|---|
| | Aged | Nonaged | Aged | Nonaged | Aged | Nonaged | Total |
| Less than 0 | 207 | 4,097 | 2,745 | 15,051 | 2,952 | 19,148 | 22,100 |
| 0 - 5 | 9,889 | 18,056 | 14,201 | 11,827 | 24,090 | 29,883 | 53,973 |
| 5 - 10 | 25,279 | 8,873 | 15,460 | 23,753 | 40,739 | 32,626 | 73,365 |
| 10 - 15 | 15,078 | 11,590 | 26,010 | 20,615 | 41,088 | 32,205 | 73,293 |
| 15 - 20 | 11,305 | 3,804 | 10,961 | 35,140 | 22,266 | 38,944 | 61,210 |
| 20 - 30 | 11,868 | 8,688 | 40,966 | 77,135 | 52,834 | 85,823 | 138,657 |
| 30 - 50 | 15,428 | 5,044 | 32,088 | 92,803 | 47,516 | 97,847 | 145,363 |
| 50 - 100 | 6,767 | 5,344 | 18,181 | 61,431 | 24,948 | 66,775 | 91,723 |
| 100 - 200 | 2,728 | 1,620 | 8,310 | 19,359 | 11,038 | 20,979 | 32,017 |
| 200 and over | 1,323 | 623 | 4,206 | 9,165 | 5,529 | 9,788 | 15,317 |
| Total | 99,872 | 67,739 | 173,128 | 366,279 | 273,000 | 434,018 | 707,018 |

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Note: Details may not add to totals due to rounding.

1/ Also includes married filing separately and head-of-household returns.

## Table 3-A

### Amount of Qualified Royalty Credit Claimed by Adjusted Gross Income, Type of Filer, and Aged Exemption

(Unpublished Tabulation, 1980 Individual Statistics of Income)

(thousands of dollars)

| Adjusted gross income class ($000) | Single returns |  | Joint returns 1/ |  | Total returns |  |  |
|---|---|---|---|---|---|---|---|
|  | Aged | Nonaged | Aged | Nonaged | Aged | Nonaged | Total |
| Less than 0 | 43 | 473 | 145 | 1,636 | 188 | 2,109 | 2,297 |
| 0 - 5 | 96 | 2,941 | 2,138 | 1,115 | 2,234 | 4,057 | 6,291 |
| 5 - 10 | 7,621 | 1,958 | 3,932 | 1,441 | 11,554 | 3,399 | 14,953 |
| 10 - 15 | 3,322 | 3 | 2,482 | 1,208 | 5,804 | 1,208 | 7,012 |
| 15 - 20 | 4,335 | 344 | 1,054 | 4,024 | 5,389 | 4,367 | 9,756 |
| 20 - 30 | 7,598 | 121 | 8,856 | 10,373 | 16,454 | 10,494 | 26,948 |
| 30 - 50 | 1,963 | 3,300 | 4,343 | 19,705 | 6,306 | 23,007 | 29,313 |
| 50 - 100 | 3,548 | 2,159 | 4,466 | 16,094 | 8,014 | 18,253 | 26,267 |
| 100 - 200 | 1,388 | 756 | 3,471 | 7,736 | 4,860 | 8,492 | 13,352 |
| 200 and over | 764 | 460 | 2,131 | 4,653 | 2,895 | 5,113 | 8,008 |
| Total | 30,679 | 12,518 | 33,021 | 67,983 | 63,698 | 80,499 | 144,197 |

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Note: Details may not add to totals due to rounding.

1/ Also includes married filing separately and head-of-household returns.

### Table 3-B

### Number of Returns Claiming Qualified Royalty Credit by Adjusted Gross Income, Type of Filer, and Aged Exemption

(Unpublished Tabulation, 1980 Individual Statistics of Income)

(thousands of dollars)

| Adjusted gross income class ($000) | Single returns |  | Joint returns 1/ |  | Total returns |  |  |
|---|---|---|---|---|---|---|---|
|  | Aged | Nonaged | Aged | Nonaged | Aged | Nonaged | Total |
| Less than 0 | 68 | 747 | 1,816 | 3,962 | 1,884 | 4,709 | 6,593 |
| 0 - 5 | 352 | 5,821 | 2,068 | 3,599 | 2,420 | 9,420 | 11,840 |
| 5 - 10 | 10,019 | 7,483 | 9,559 | 4,930 | 19,578 | 12,413 | 31,991 |
| 10 - 15 | 7,868 | 41 | 7,893 | 2,781 | 15,579 | 2,822 | 18,401 |
| 15 - 20 | 5,809 | 653 | 3,565 | 11,255 | 9,374 | 11,908 | 21,282 |
| 20 - 30 | 8,272 | 158 | 11,652 | 24,995 | 19,924 | 25,153 | 45,077 |
| 30 - 50 | 6,221 | 3,739 | 8,836 | 44,436 | 15,057 | 48,175 | 63,232 |
| 50 - 100 | 4,450 | 3,261 | 8,849 | 34,204 | 13,299 | 37,465 | 50,764 |
| 100 - 200 | 1,738 | 1,187 | 5,255 | 13,603 | 6,993 | 14,790 | 21,783 |
| 200 and over | 896 | 591 | 2,898 | 7,162 | 3,794 | 7,753 | 11,547 |
| Total | 45,511 | 23,681 | 62,391 | 150,927 | 107,902 | 174,608 | 282,510 |

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Note: Details may not add to totals due to rounding.

1/ Also includes married filing separately and head-of-household returns.

Table 4

### Percentage Depletion Reported As a Preference Item for the Corporate Minimum Tax by Corporations Reporting Gross Royalties

(Unpublished Tabulation, 1980 Corporate Statistics of Income)

| SIC | Industry description | Number of returns | Preference 1/ |
|---|---|---|---|
| | | | ($000) |
| 1330 | Oil and gas drilling | 488 | 150,525 |
| 2910 | Oil refining | 35 | 607,128 |

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1/ Percentage depletion exceeding basis at beginning of year.

Tables 5A and 5B report, respectively, the preference amount of percentage depletion and the number of returns reporting percentage depletion, for individual taxpayers having net royalty income and subject to the add-on minimum tax in 1980. The data in Tables 5A and 5B are tabulated by AGI class, type of filer, and the presence or absence of the aged exemption.

Data on the use of percentage depletion by corporate royalty owners was presented above in Table 4 as part of the response to question #3.

10. To what extent has percentage depletion caused independent producers or royalty owners to become subject to either the corporate or individual tax provisions? How many independent producers are subject to either the individual or corporate minimum tax? Of these, how many are limited partners?

In 1980, the last year for which data are available, both percentage depletion (in excess of adjusted basis) and intangible drilling costs (in excess of net income from oil and gas properties) were preferences for purposes of the individual add-on minimum tax and percentage depletion (in excess of adjusted basis) was a preference item under the corporate minimum tax. Percentage depletion was available to both royalty owners and independent producers, but not to integrated producers, while expensing of intangible drilling costs was available to all producers with a working interest in the property, but not to royalty owners. Finally, no specific information is available from tax returns that would allow separate identification of independent producers and royalty owners. Indeed, some taxpayers may be both independent producers and royalty owners.

Tables 6 and 7 show, for individuals and corporations (in oil and gas), respectively, data on those filing under the minimum tax and having percentage depletion as a preference item.

Tables 5A and 5B report, respectively, the preference amount of percentage depletion and the number of returns reporting percentage depletion, for individual taxpayers having net royalty income and subject to the add-on minimum tax in 1980. The data in Tables 5A and 5B are tabulated by AGI class, type of filer, and the presence or absence of the aged exemption.

Data on the use of percentage depletion by corporate royalty owners was presented above in Table 4 as part of the response to question #3.

10. To what extent has percentage depletion caused independent producers or royalty owners to become subject to either the corporate or individual tax provisions? How many independent producers are subject to either the individual or corporate minimum tax? Of these, how many are limited partners?

In 1980, the last year for which data are available, both percentage depletion (in excess of adjusted basis) and intangible drilling costs (in excess of net income from oil and gas properties) were preferences for purposes of the individual add-on minimum tax and percentage depletion (in excess of adjusted basis) was a preference item under the corporate minimum tax. Percentage depletion was available to both royalty owners and independent producers, but not to integrated producers, while expensing of intangible drilling costs was available to all producers with a working interest in the property, but not to royalty owners. Finally, no specific information is available from tax returns that would allow separate identification of independent producers and royalty owners. Indeed, some taxpayers may be both independent producers and royalty owners.

Tables 6 and 7 show, for individuals and corporations (in oil and gas), respectively, data on those filing under the minimum tax and having percentage depletion as a preference item.

## Table 5-A

## Percentage Depletion Claimed as a Preference Item 2/ for the Minimum Tax by Taxpayers Reporting Net Royalty Income, by Adjusted Gross Income, Type of Filer, and Aged Exemption

(Unpublished Tabulation, 1980 Individual Statistics of Income)

(thousands of dollars)

| Adjusted gross income class ($000) | Single returns |  | Joint returns 1/ |  | Total returns |  |  |
|---|---|---|---|---|---|---|---|
|  | Aged | Nonaged | Aged | Nonaged | Aged | Nonaged | Total |
| Less than 0 | 894 | 0 | 1,745 | 0 | 2,639 | 0 | 2,639 |
| 0 - 5 | 0 | 0 | 0 | 3 | 0 | 3 | 3 |
| 5 - 10 | 0 | 0 | 0 | 275 | 0 | 275 | 275 |
| 10 - 15 | 0 | 0 | 20,028 | 771 | 20,028 | 771 | 20,799 |
| 15 - 20 | 0 | 0 | 0 | 618 | 0 | 618 | 618 |
| 20 - 30 | 0 | 3,236 | 3,253 | 15,462 | 3,253 | 15,462 | 18,715 |
| 30 - 50 | 15,669 | 1,268 | 2,344 | 15,397 | 18,014 | 16,665 | 34,679 |
| 50 - 100 | 30,212 | 24,223 | 38,107 | 93,108 | 68,319 | 117,331 | 185,650 |
| 100 - 200 | 13,760 | 8,675 | 65,330 | 144,252 | 79,091 | 152,927 | 232,018 |
| 200 and over | 74,949 | 43,955 | 216,139 | 375,455 | 291,087 | 419,410 | 710,497 |
| Total | 135,485 | 84,156 | 346,946 | 665,255 | 482,432 | 749,411 | 1,231,843 |

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Note: Details may not add to totals due to rounding.

1/ Also includes married filing separately and head-of-household returns.

2/ Percentage depletion in excess of basis at beginning of year.

### Table 5-B

### Number of Returns Reporting Net Royalty Income and Claiming Percentage Depletion 2/ as a Preference Item under the Minimum Tax by Adjusted Gross Income, Type of Filers, and Aged Exemption

(Unpublished Tabulation, 1980 Individual Statistics of Income)

(thousands of dollars)

| Adjusted gross income class ($000) | Single returns | | Joint returns 1/ | | Total returns | | |
|---|---|---|---|---|---|---|---|
| | Aged | Nonaged | Aged | Nonaged | Aged | Nonaged | Total |
| Less than 0 | 18 | 49 | 16 | 436 | 34 | 485 | 519 |
| 0 - 5 | 0 | 0 | 0 | 1 | 0 | 1 | 1 |
| 5 - 10 | 0 | 0 | 0 | 184 | 0 | 184 | 184 |
| 10 - 15 | 0 | 0 | 364 | 244 | 364 | 244 | 608 |
| 15 - 20 | 0 | 0 | 0 | 839 | 0 | 839 | 839 |
| 20 - 30 | 0 | 99 | 194 | 991 | 194 | 1,090 | 1,284 |
| 30 - 50 | 1,355 | 32 | 86 | 1,425 | 1,441 | 1,457 | 2,898 |
| 50 - 100 | 1,568 | 1,562 | 1,912 | 5,505 | 3,480 | 7,067 | 10,547 |
| 100 - 200 | 420 | 304 | 1,486 | 4,199 | 1,906 | 4,503 | 6,409 |
| 200 and over | 636 | 339 | 1,641 | 3,675 | 2,277 | 4,014 | 6,291 |
| Total | 3,997 | 2,385 | 5,699 | 17,499 | 9,696 | 19,884 | 29,580 |

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Note: Details may not add to totals due to rounding.

1/ Also includes married filing separately and head-of-household returns.

2/ Percentage depletion in excess of basis at beginning of year.

These data include all taxpayers (whether independent producers, royalty owners, or both) reporting percentage depletion as a preference item, whether or not they have other preferences.

Tables 8 and 9, by comparison, show the sum of the two preference items for taxpayers reporting percentage depletion and/or IDCs as a preference item in 1980. As noted above, IDCs were not a preference item under the corporate minimum tax. Certain business trusts and personal holding companies filing as corporations were, however, subject to the individual add-on minimum tax. These taxpayers are included in the data on corporate reporting of percentage depletion and/or IDC preferences shown in Table 9.

Finally, Tables 10 and 11 show percentage depletion reported as a preference item for those taxpayers not reporting IDCs as a preference item.

16. Numerous witnesses suggested that the oil and gas production industry pays the highest (or an unusually high) rate of tax. Please comment.

(a) With regard to effective corporate rates, what rate of tax do the independent and the major corporate producers pay? (average rate, marginal rate, other?)

(b) What impact does the windfall profit tax have on these rates of taxation?

(c) How do the various tax rates compare to the taxation of other industries?

As the Treasury Department has indicated in its previous submission, no one number can adequately summarize the effective tax rates on oil investments, because the rates vary greatly with

Table 6

### Individuals Subject to the Minimum Tax Claiming Percentage Depletion as a Preference Item

(Unpublished Tabulation, 1980 Individual *Statistics of Income*)

| Adjusted gross income class | Number of returns | Percent distribution | Dollar amount | Percent distribution | Average percentage depletion per return for returns having percentage depletion |
|---|---|---|---|---|---|
| | | ( percent ) | ($ thousands) | ( percent ) | (.... dollars ....) |
| Less than 0 | 1,524 | 2.1% | $ 71,051 | 3.3% | $46,621 |
| 0 - $5,000 | 542 | 0.8 | 9,200 | 0.4 | 16,974 |
| 5,000 - 10,000 | 401 | 0.6 | 3,773 | 0.2 | 9,409 |
| 10,000 - 15,000 | 623 | 0.9 | 21,020 | 1.0 | 33,740 |
| 15,000 - 20,000 | 2,134 | 3.0 | 28,096 | 1.3 | 13,166 |
| 20,000 - 30,000 | 3,618 | 5.1 | 50,768 | 2.3 | 14,038 |
| 30,000 - 50,000 | 8,093 | 11.3 | 66,090 | 3.0 | 8,166 |
| 50,000 - 100,000 | 21,871 | 30.6 | 350,312 | 16.1 | 16,017 |
| 100,000 - 200,000 | 17,593 | 24.6 | 430,090 | 19.8 | 24,447 |
| Greater than 200,000 | 15,050 | 21.1 | 1,139,398 | 52.5 | 75,708 |
| Total | 71,449 | 100.0% | $2,169,816 | 100.0% | $30,369 |
| Total 1980 returns .... | 93,902,469 | | | | |
| Percent of 1980 returns having minimum tax -- percentage depletion (%) | 0.08% | | | | |

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Note: Details may not add to totals due to rounding.

### Table 7

### Corporations Subject to the Minimum Tax Claiming Percentage Depletion as a Preference Item

(Unpublished Tabulation, 1980 Corporate Statistics of Income)

| SIC | Industry Description | Number of returns | Total depletion including cost depletion | Tax preference percentage depletion 1/ |
|---|---|---|---|---|
| | | | (........ $ thousands | .......) |
| 1330 | Oil and gas drilling ........ | 1,033 | 516,525 | 281,201 |
| 2910 | Oil refining ................ | 49 | 1,621,354 | 629,455 |

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1/ Percentage depletion exceeding basis at beginning of year.

## Table 8

### Individuals Subject to the Minimum Tax and Claiming Either Percentage Depletion or Intangible Drilling Costs as a Preference Item

(Unpublished Tabulation, 1980 Individual Statistics of Income)

| Adjusted gross income class | Number of returns | Percent of returns | Dollar value of preferences | Percent of value | Average value of preference for returns with preference |
|---|---|---|---|---|---|
| | | (percent) | ($thousands) | (percent) | (dollars) |
| Less than 0 | 3,230 | 2.7% | 242,634 | 5.6% | $75,119 |
| $ 0 - $5,000 | 780 | 0.6 | 23,581 | 0.5 | 30,232 |
| 5,000 - 10,000 | 474 | 0.4 | 9,066 | 0.2 | 19,127 |
| 10,000 - 15,000 | 2,978 | 2.5 | 86,136 | 2.0 | 28,924 |
| 15,000 - 20,000 | 6,096 | 5.0 | 108,073 | 2.5 | 17,729 |
| 20,000 - 30,000 | 7,096 | 5.9 | 114,535 | 2.7 | 16,141 |
| 30,000 - 50,000 | 15,052 | 12.4 | 257,743 | 6.0 | 17,124 |
| 50,000 - 100,000 | 36,442 | 30.1 | 827,778 | 19.2 | 22,715 |
| 100,000 - 200,000 | 27,632 | 22.8 | 859,576 | 20.0 | 37,108 |
| Greater than 200,000 | 21,179 | 17.5 | 1,773,772 | 41.2 | 83,751 |
| Total ......... | 120,059 | 100.0% | $4,302,894 | 100.0% | $35,840 |
| Total of 1980 returns ....... | 93,902,467 | | | | |
| Percent of 1980 return with minimum tax showing these preference items (percent) ..... | 0.13% | | | | |

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Note: Details may not add to totals due to rounding.

1/ Sum of percentage depletion in excess of beginning of year basis and IDCs in excess of net income from oil and gas properties if either is claimed.

### Table 9

### Corporations Subject to the Minimum Tax Reporting Percentage Depletion, Intangible Drilling Costs, or Both, as Preference Items

(Unpublished Tabulation, 1980 Corporate Statistics of Income)

| SIC | Industry description | Number of returns | Sum of percentage depletion and IDC preference 1/ |
|---|---|---|---|
| | | | ($000) |
| 1330 | Oil and gas drilling | 1053 | 296,472 |
| 2910 | Oil refining | 49 | 629,455 |

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1/ Percentage depletion exceeding basis at beginning of year and IDCs in excess of net income from oil and gas properties.

2/ Intangible drilling costs were not generally a preference item for corporations. However, certain business trusts and personal holding companies, filing as corporations, were subject to the individual add-on minimum tax. These are included here.

Table 10

**Percentage Depletion Claimed as a Preference Item for the Minimum Tax by Taxpayers Claiming No Intangible Drilling Costs as a Preference Item**

(Unpublished Tabulations, 1980 Individual *Statistics of Income*)

| Adjusted gross income class | Number of returns | Percent of returns | Dollar value of 1/ preference | Percent of value | Average value per return for returns having preference |
|---|---|---|---|---|---|
| ($000) | | (. percent ..) | ($ thousands) | (percent) | (.... dollars ...) |
| Less than 0 | 931 | 2.2% | $ 67,747 | 3.5% | $ 72,768 |
| 0 - 5 | 513 | 1.2 | 9,127 | 0.5 | 17,791 |
| 5 - 10 | 186 | 0.4 | 3,567 | 0.2 | 19,177 |
| 10 - 15 | 601 | 1.4 | 20,984 | 1.1 | 34,915 |
| 15 - 20 | 1,531 | 3.5 | 26,726 | 1.4 | 17,457 |
| 20 - 30 | 2,673 | 6.2 | 46,694 | 2.4 | 17,469 |
| 30 - 50 | 4,740 | 11.0 | 51,297 | 2.7 | 10,822 |
| 50 - 100 | 14,140 | 32.7 | 300,936 | 15.6 | 21,283 |
| 100 - 200 | 9,755 | 22.6 | 379,335 | 19.7 | 38,886 |
| 200 and over | 8,176 | 18.9 | 1,023,928 | 53.0 | 125,236 |
| Total | 43,246 | 100.0% | $1,930,337 | 100.0% | $ 44,636 |

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1/ Percentage depletion in excess of adjusted basis at beginning of year.
Details may not add to totals due to rounding.

### Table 11

### Corporations Subject to the Minimum Tax Reporting Percentage Depletion, But Not Intangible Drilling Costs, as a Preference Item

(Unpublished Tabulation, 1980 Corporate Statistics of Income)

| SIC | Industry description | Number of returns | Amount of preference 1/ ($000) |
|---|---|---|---|
| 1330 | Oil and gas drilling | 1,015 | 278,798 |
| 2910 | Oil refining | 49 | 629,455 |

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1/ Percentage depletion exceeding basis at beginning of year.

characteristics of the oil property and type of investment. These tax rates vary among types of investments because 1) different types of capital costs are subject to different capital recovery rules, and 2) the windfall profit tax rates differ significantly by type of investment.

The Treasury staff has prepared estimates of effective tax rates on the return to investment in some hypothetical oil wells. These estimates are presented in Table 12. In all of the examples in Table 12, it is assumed that the oil company confronts the windfall profit tax rate and base applied to new oil. Thus, the higher rates on some investments to increase output from existing wells that are classified as tier 1 or tier 2 are not considered in these calculations. In addition, the tax rates shown in Table 12 are only those applied at the corporate level; they do not take account of additional income taxes paid by individual shareholders on dividends and capital gains arising from the return to oil investments. These features of the calculations need to be kept in mind in comparing these estimates of effective tax rates with estimates provided by the Congressional Budget Office and other sources.

As noted in Treasury's previous submission, the effective tax rate is computed as the percentage reduction in before-tax return over the life of the asset due to the corporate income tax and the windfall profit tax. It is not a measure of the current tax flow divided by current income, but rather is a measure of how much the tax system affects the expected return on prospective investments. A negative effective tax rate indicates that the after-tax return over the life of the investment is larger than the before-tax return.

Table 12 presents estimates of effective tax rates on the return to new oil wells developed in 1983 by integrated producers and independent producers, with and without the windfall profit tax on new oil. Separate calculations are presented for already discovered oil and for undiscovered oil. In the case of discovered oil, it is assumed that the developer must bid for the drilling rights and that the bid price established is that which makes the expected after-tax return equal to 10 percent. In the case of undiscovered oil, it is assumed that the expected number of dry holes, per successful well, is such that the overall expected after-tax return from all wells, both successful and unsuccessful, is 10 percent.

The calculations in Table 12 are only illustrative, not definitive, because the results are sensitive to what is assumed about the discount rate of investors (in these calculations, it is 10 percent), the share of costs attributable to different types of investments (IDCs and 5 year ACRS property), the rate of inflation, and the level and expected growth rate of oil prices. Different assumptions would alter the estimated tax rates.

The calculations summarized in Table 12 show that the effective tax rate varies greatly among the different hypothetical investments. Effective tax rates are much higher for investments in developing known oil reserves than for investments in properties where the percentage of dry holes is greater. In the former case, land acquisition costs must be capitalized while in the latter case intangible drilling costs for both dry holes and producing wells can be expensed. In contrast, the windfall profit tax does not significantly affect the effective tax rate on the return from new oil properties because the tax on new oil, especially after the changes in the Economic Recovery Tax Act in 1981 and the recent decline in world oil prices, is quite small relative to the amount of capital invested.

The effective tax rate on independent corporate producers is not much lower than the tax rate on major producers for oil properties with high land acquisition costs. This is so mainly because, by choosing percentage depletion, the independent producers forego the cost depletion deductions on the high land value. On the other hand, for oil properties where the expected ratio of dry holes to successful wells is large, making the cost of land relatively small, the availability of percentage depletion provides a significant advantage to independent producers. In this case, the amount of investment that would otherwise be included in the basis for cost depletion (i.e., the land value) is small.

Finally, a clear comparison of the effective tax rates on oil well development and the effective tax rates on returns to other, non-oil investments cannot be made both because the range of effective tax rates on oil properties is so large and also because the range of effective tax rates on other investments is large. Compared to the effective tax rates on most 5-year ACRS property (generally around 0), the effective tax rate on oil is generally higher, except for marginal, high-risk properties developed by independent producers. Compared to the effective tax rates on investment in inventories (generally around 46 percent for large corporations), the effective tax rate on all oil properties is relatively low. Compared to the effective tax rate on corporate investments in structures financed by equity capital (generally positive, but less than 46 percent), the effective tax rate on investments in some oil properties is relatively high and on other oil properties relatively low.

## Further Response to Request from Congressman Campbell

3. In the most recent estimates for 1983-1987, what are the revenue projections for each tier and type of producer?

Table 13 provides an estimate of windfall profit tax revenues by tier and type of producer from 1980 to 1988. These

Table 12

Computation of Effective Tax Rate on Selected Hypothetical Investments In New Oil Wells

Corporate Level Tax Rates: Equity Capital 1/

| | After-tax return (percent) | Before-tax return (percent) | Effective tax rate (percent) |
|---|---|---|---|
| **Integrated Producers** | | | |
| 1. Discovered oil | | | |
| a. with windfall profit tax | 10.0 | 16.0 | 37.4 |
| b. no windfall profit tax | 10.0 | 15.5 | 35.6 |
| 2. Undiscovered oil | | | |
| a. with windfall profit tax | 10.0 | 10.4 | 4.2 |
| b. no windfall profit tax | 10.0 | 10.0 | 0.0 |
| **Independent Producers** | | | |
| 1. Discovered oil | | | |
| a. with windfall profit tax | 10.0 | 15.9 | 37.0 |
| b. no windfall profit tax | 10.0 | 15.4 | 35.2 |
| 2. Undiscovered oil | | | |
| a. with windfall profit tax | 10.0 | 8.6 | -16.3 |
| b. no windfall profit tax | 10.0 | 8.2 | -21.8 |

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1/ Does not include further taxes on corporate dividend payments and on capital gains received by individuals from sales of corporate shares.

estimates are consistent with economic assumptions used in preparing the April, 1983 update of the budget, the most recent set of budget assumptions for which net windfall profit tax liabilities are available. Net liabilities reported in the table exclude liabilities on Federally-owned oil and also exclude reductions in income tax liabilities that result because the windfall profit tax is deductible in computing taxable income of oil producers.

As a result of the further work in preparing these estimates, the Treasury has revised its earlier estimates supplied to the Subcommittee on the effect of legislation enacted since the Crude Oil Windfall Profit Tax Act of 1980 on windfall profit tax revenue by tier and type of producer. These estimates were presented in Table 6 of Treasury's previous submission. The revised estimates of the effect of recent legislation on windfall profit tax revenue by tier and type of producers are shown in Table 14.

### Table 13
### Net Windfall Profit Tax Liability
### by Tier and Type of Producer

April Update Assumptions

($ millions)

|  | Calendar Years |  |  |  |  |  |  |  |  |
|---|---|---|---|---|---|---|---|---|---|
|  | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 |
| Tier 1: |  |  |  |  |  |  |  |  |  |
| Non-Alaska: |  |  |  |  |  |  |  |  |  |
| Integrated | 2,062 | 7,595 | 5,026 | 3,193 | 2,359 | 2,049 | 1,753 | 1,511 | 1,207 |
| Independent | 261 | 901 | 645 | 425 | 323 | 281 | 240 | 207 | 166 |
| Royalty | 317 | 1,129 | 671 | 453 | 350 | 272 | 229 | 197 | 158 |
| Alaska: |  |  |  |  |  |  |  |  |  |
| Integrated | 378 | 1,368 | 699 | 206 | 1 | 58 | 165 | 267 | 297 |
| Tier 2: |  |  |  |  |  |  |  |  |  |
| Integrated | 710 | 897 | 613 | 387 | 302 | 313 | 331 | 346 | 337 |
| Independent | 311 | 434 | 321 | 0 | 0 | 0 | 0 | 0 | 0 |
| Royalty | 234 | 278 | 158 | 107 | 87 | 82 | 88 | 93 | 92 |
| Tier 3: |  |  |  |  |  |  |  |  |  |
| Heavy: |  |  |  |  |  |  |  |  |  |
| Integrated | 113 | 152 | 79 | 17 | 0 | 0 | 0 | 0 | 0 |
| Independent | 7 | 10 | 5 | 1 | 0 | 0 | 0 | 0 | 0 |
| Royalty | 18 | 22 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| New: |  |  |  |  |  |  |  |  |  |
| Integrated | 218 | 470 | 313 | 137 | 59 | 50 | 39 | 39 | 22 |
| Independent | 80 | 173 | 119 | 54 | 24 | 20 | 16 | 16 | 9 |
| Royalty | 49 | 105 | 59 | 26 | 12 | 9 | 7 | 7 | 4 |
| Incremental tertiary: |  |  |  |  |  |  |  |  |  |
| Integrated | 4 | 27 | 81 | 59 | 30 | 33 | 38 | 38 | 23 |
| Independent | 1 | 9 | 28 | 21 | 11 | 12 | 14 | 14 | 8 |
| Royalty | 1 | 6 | 17 | 14 | 7 | 8 | 9 | 9 | 6 |
| All tiers: |  |  |  |  |  |  |  |  |  |
| Integrated | 3,486 | 10,508 | 6,811 | 4,000 | 2,751 | 2,503 | 2,325 | 2,200 | 1,886 |
| Independent | 661 | 1,527 | 1,119 | 501 | 357 | 313 | 269 | 236 | 183 |
| Royalty | 618 | 1,539 | 905 | 600 | 456 | 371 | 334 | 306 | 260 |
| Total | 4,766 | 13,575 | 8,835 | 5,100 | 3,565 | 3,186 | 2,928 | 2,742 | 2,328 |

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Note: Details may not add to totals due to rounding.

## Table 14

## Effect of Enacted Legislation on Net Windfall Profit Tax Liabilities by Tier and Type of Producer 1/

April Update Assumptions

($ millions)

| | Calendar Years | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 |
| **Omnibus Reconciliation Act of 1980:** | | | | | | | | | |
| Royalty owners credit: | | | | | | | | | |
| Tier 1 | -81 | -- | -- | -- | -- | -- | -- | -- | -- |
| Tier 2 | -19 | -- | -- | -- | -- | -- | -- | -- | -- |
| Tier 3 | -10 | -- | -- | -- | -- | -- | -- | -- | -- |
| **Economic Recovery Tax Act:** | | | | | | | | | |
| Royalty owners credit and exemptions: | | | | | | | | | |
| Tier 1 | -- | -216 | -312 | -216 | -175 | -190 | -168 | -148 | -123 |
| Tier 2 | -- | -50 | -72 | -50 | -42 | -52 | -55 | -57 | -56 |
| Tier 3 | -- | -26 | -40 | -22 | -8 | -9 | -9 | -9 | -5 |
| Reduction of tax on newly discovered oil: | | | | | | | | | |
| Tier 3 -- Integrated | -- | -- | -29 | -30 | -23 | -30 | -47 | -52 | -28 |
| Independent | -- | -- | -10 | -11 | -8 | -11 | -17 | -17 | -10 |
| Royalty | -- | -- | -7 | -8 | -6 | -7 | -12 | -7 | -7 |
| Exemption for stripper oil produced by independent producers: | | | | | | | | | |
| Tier 2 -- Independent | -- | -- | -- | -237 | -179 | -181 | -186 | -191 | -183 |
| Exemption for certain charities: | | | | | | | | | |
| Unassignable by tier | -- | -10 | -10 | -10 | -10 | -10 | -10 | -10 | -10 |
| **Tax Equity and Fiscal Responsibility Act:** | | | | | | | | | |
| Elimination of tax adjustment: | | | | | | | | | |
| Tier 1 Alaska -- integrated | -- | -- | 97 | 0 | 24 | 24 | 24 | 24 | 24 |

### Effect of Enacted Legislation on Net Windfall Profit Tax Liabilities by Tier and Type of Producer

($ millions)

| | Years | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 |
| Technical Corrections Act of 1982: | | | | | | | | | |
| Reclassification of NPR 2/ | — | — | — | — | — | — | — | — | — |
| Trust beneficiaries -- royalty owner: | | | | | | | | | |
| Tier 1 | — | — | -44 | -28 | -19 | -17 | -14 | -12 | -10 |
| Tier 2 | — | — | -10 | -6 | -5 | -5 | -4 | -5 | -5 |
| Tier 3 | — | — | -6 | -3 | -1 | -1 | -1 | -1 | 0 |
| By Tier and Type of Producer: | | | | | | | | | |
| Tier 1 — Alaska — integrated | — | — | — | 97 | 0 | 24 | 24 | 24 | 24 |
| Tier 1 — Non-Alaska -- royalty owners | -81 | -216 | -356 | -244 | -194 | -207 | -182 | -160 | -133 |
| Tier 2 — Independent | — | — | — | -237 | -179 | -181 | -186 | -191 | -183 |
| — Royalty owners | -19 | -50 | -82 | -56 | -47 | -57 | -59 | -62 | -61 |
| Tier 3 — New oil: | | | | | | | | | |
| Integrated | — | — | -29 | -30 | -23 | -30 | -47 | -52 | -28 |
| Independent | — | — | -10 | -11 | -8 | -11 | -17 | -17 | -10 |
| Royalty owners | -10 | -26 | -53 | -33 | -15 | -17 | -22 | -17 | -12 |
| Unassignable | — | -10 | -10 | -10 | -10 | -10 | -10 | -10 | -10 |

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1/ Revision of Table 6 of previous submission.
2/ No effect on net liabilities.

Chairman **Rangel**. The committee welcomes the Oklahoma congressional delegation.

We have included in our agenda a panel to represent the Oklahoma Independent Petroleum Association, as well as some other people that were suggested by the congressional delegation.

I understand, Mr. Chairman, that you have a prepared statement.

You may proceed.

## STATEMENT OF HON. JAMES R. JONES, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF OKLAHOMA

Mr. **Jones**. Thank you very much, Mr. Chairman.

First of all, let me thank you and the subcommittee for allowing the entire Oklahoma congressional delegation to testify at one time.

We are very unified on this issue. We appreciate the opportunity to testify. We also appreciate your answering our request to allow the independent producers from Oklahoma to testify before this subcommittee and to answer any questions you may have on the practical as well as the financial aspects of the oil industry.

I would like to have included in the record the entire statement, which is a statement on behalf of the entire Oklahoma congressional delegation.

Chairman **Rangel**. Without objection, Mr. Jones.

Mr. **Jones**. First of all, Mr. Chairman, let me just paint the economic picture in Oklahoma. We are experiencing a considerable increase in unemployment. In some counties from last year the unemployment levels have tripled, and at least doubled. Over a third of the counties in Oklahoma have unemployment rates in excess of 10 percent. Most of this is—certainly a great portion, if not most of this—is due to decline and the depression in the oil industry in Oklahoma.

A year ago, there were 788 oil and gas rigs in production in our State. There are 232 rigs in use today, a drop of 71 percent. We have an unemployment rate in the oil industry of 20 percent in our State.

So, it is a very serious situation.

In my part of Oklahoma, the part that is represented by Mike Synar, myself, Mickey Edwards, the northeastern part, there was a 72-percent increase in bankruptcies in the first quarter of this calendar year. And so the oil and gas industry is suffering desperately, and the boom times have fled.

Oklahoma is bearing the heavy burden of the recession that has not yet hit bottom. Although we are accustomed to the roller coaster ride of the energy industry which is part of our heritage, clearly it is hurting our economy at the present time.

The capital investment is the lifeblood of the oil and gas industry. It is also the lifeblood of the thousands of jobs created by the industry. The tax provisions under review today are essential to the continued investment and to increased domestic energy production. Independent oil and gas producers have historically drilled 85 to 90 percent of the wildcat wells in this Nation. They have developed most of the new fields in America, and they produce over 50 percent of the oil recovered each day in the lower 48 States.

Nevertheless, the very nature of the entire industry is speculative, and it is imperative that the industry have capital if we hope to make this Nation self-reliant with regard to energy resources.

We have made remarkable progress in recent years because of incentives to produce more energy, and we should not let that trend be reversed.

Now, of those tax incentives that are important, particularly to the independent, let me first mention the percentage depletion allowances. These are very necessary, as the Treasury witness pointed out, as a capital investment incentive, particularly for independents. The present law mandates that the percentage depletion, which just a short time ago was 27½ percent, and then phased down to 22 percent, will drop to 15 percent by next year. We believe this percentage is too low; that it should at least be frozen at the 22-percent level.

Intangible drilling costs obviously comprise the single largest element of expenditures for the producing industry.

IDC's are 40 percent of the total outlays for exploration and development. They represent approximately 70 percent of the total cost of drilling and equipping a successful well for production.

Last year, the Reagan administration and Congress considered subjecting IDC's to a minimum tax, both for individual and corporate levels, and the ramifications of that became immediately apparent, even to the point that then Secretary of Energy James Edwards wrote in a letter to a member of our Oklahoma delegation, and I quote him:

> My tax economists calculated a 15-to-20 percent reduction in exploratory drilling by independents based on the impact of the proposed minimum tax on the after-tax cost of drilling.

In light of those facts, Congress undertook another course of action which represented a fair and equitable compromise for all affected parties. We do not believe the economic climate which discouraged the enactment of other options has changed. Indeed, as our statement illustrates, the economic conditions have deteriorated.

So, the tangible drilling costs, and percentage depletion, are vitally important to independents, as well as the tier 1 and tier 2 reduced tax rates for independent producers.

It is particularly important at this time in our State, because of the collapse of the Penn Square Bank, it is becoming increasingly more difficult to raise the capital for the speculative ventures of oil production. Not only are the traditional sources of capital from financial institutions drying up, but it becomes increasingly difficult to attract outside capital to a drilling venture.

Without these particular tax incentives, there just simply would not be enough capital to do any kind of drilling activity that would lead toward energy independence, and certainly without that, we will have no leverage against the OPEC's of this world who would then be back in the saddle, controlling prices and production.

So, Mr. Chairman, I will not continue with the rest of my testimony, because you do have it in its entirety.

I would point out that the Oklahoma delegation strongly urges you to listen to the producers who will testify later in this hearing, be mindful of their testimony, and the problems that the industry is experiencing.

I know that they can answer most of the questions that perhaps are troubling you.

We thank you again.

[The prepared statement follows:]

### STATEMENT OF THE OKLAHOMA DELEGATION

Mr. Chairman, the Oklahoma Congressional Delegation would like to thank you for the opportunity to appear before you today. The issues that you will be discussing in the next two days, and the testimony you will be receiving, are of great importance not only to our state, Oklahoma, but they are also critical to the economic viability of the oil and gas industry in general.

One year ago, there were 788 oil and gas rigs in production in Oklahoma. Today, 232 rigs are in use—a drop of 71 percent. This represents the smallest number of working rigs in Oklahoma in seven years. Twenty percent of our oil and gas industry work force is unemployed.

One year ago, the unemployment rate for Oklahoma was 4.8 percent. Today, unemployment stands at 8.8 percent, the highest in Oklahoma's history. One-third of Oklahoma's counties have unemployment rates over ten percent—well above the national average.

Although this figure may not seem high when compared to the tragic figures in other parts of America, we would point out that in most counties in Oklahoma, unemployment has doubled from one year ago and tripled from two years ago.

Business bankruptcies are up by 72 percent in the first quarter of 1983 in Northeastern Oklahoma. Sadly, this trend is reflected throughout the state.

In short, Mr. Chairman, Oklahoma and the oil and gas industry are suffering desperately. The boom times have fled, and Oklahoma is bearing the heavy burden of a recession that has not yet hit bottom.

Oklahomas are used to the roller coaster ride that is known as the oil and gas industry. It is part of our heritage, and we are proud of the energy production that is synonymous with our state. We will continue to work hard throughout this troubling period, and we will retian our faith in the industry.

Capital investment is the lifeblood of the oil and gas industry. It is also the lifeblood of the thousands of jobs created for Oklahomas because of the industry. The tax provisions under [illegible] today are essential to that continued investment and to increased domestic [illegible] production.

Independent oil and [illegible] have historically drilled 85 to 90 percent of the wildcat wells in this nation. [illegible] have developed most of the new fields in America, and they produce over 50 [illegible] of the oil recovered each day in the lower 48 states.

Nevertheless, the very [illegible] entire industry is speculative, and it is imperative that the industry [illegible] if we hope to make this nation self-reliant with regard to energy [illegible] made remarkable progress in recent years because of the incentives [illegible] more energy. We cannot allow that trend to be reversed.

Mr. Chairman, each of the provisions this subcommittee will be reviewing is in place for a specific purpose. During the debate on the windfall profits tax, which this delegation opposed, it was agreed that percentage depletion allowances were necessary for capital investment purposes. Unfortunately, however, the present law mandates that the percentage depletion allowance be phased down to 15 percent by next year. We believe the percentage is too low. The percentage depletion allowance should be returned to 22 percent and frozen at that level.

Intangible drilling costs comprise the single largest element of expenditures for the producing industry. IDCs are 40 percent of the total outlays for exploration and development, and represent approximately 70 percent of the total cost of drilling and equipping a successful well for production. Last year, the Reagan Administration and Congress considered subjecting intangible drilling costs to a minimum tax, both at the individual and corporate level.

The ramifications of this proposal became immediately apparent to all concerned parties. In fact, Mr. Chairman, former Secretary of Energy James Edwards underscored the impact of this action in a letter to a member of the Oklahoma Delegation. The Secretary, basing his comments on a Department of Energy study concluded: "My tax economist has calculated a 15-20 percent reduction in exploartory drilling by indpendents, based on the impact of the proposed minimum tax on the after-tax cost of drilling."

In light of these facts, the Congress undertook another course of action which represented a fair and equitable compromise for all affected intersets. We do not believe the economic climate which discouraged the enactment of other options has changed; indeed, as our statement illustrates, the economic conditions have deteriorated. Any variation from the compromise could bring disastrous consequences.

This delegation fought for the reduced tax rates on Tier I and Tier II oil for independent producers because of the risks these producers take in finding energy for the nation. Any person who has ever spent time on a drilling rig can appreciate the courage and risk implicit in going several miles into the earth in the mere hope of finding oil and gas.

We supported the exemption of stripper oil. The category is clearly defined as any well producing less than 10 barrels per day, and the majority of wells in Oklahoma are of this nature. It is obivously necessary to provide incentives for the continued production in this category.

We supported the per barrel exemption for royalty owners, It is simple fairness that these small investors be entitled to a fair return on their capital. It is also unfair to burden these individuals with the many administrative headaches which have come about because of the windfall profits tax.

Mr. Chairman, representatives of the oil and gas industry will be testifying to this body, and we are confident they will present detailed facts and analyses to supplement our comments. We would particularly like to thank you for allowing representatives of the industry in Oklahoma to share their views with the subcommittee. The Oklahoma delegation urges you to listen with an open mind to their testimony and to be mindful of the problems the industry is experiencing at this time.

The fate of our state is linked to the future of the oil and gas industry, and we trust you will treat this tremendous responsibility with care and diligence. Thank you.

Mr. JONES. At this time, I would like to ask my colleagues in the order of congressional districts if they have any statements they would like to make.

Mr. Synar?

Chairman RANGEL. We expect to hear from Senator David Boren sometime today as well. I state that for the record, since I am certain that the delegation knew that.

If there are any other Members of the Oklahoma delegation with a statement, please proceed.

## STATEMENT OF HON. MIKE SYNAR, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF OKLAHOMA

Mr. SYNAR. I represent District No. 2.

First of all, let me thank you, Mr. Chairman, for giving us the opportunity to testify today. I cannot add much more to what Jim said. I would summarize it this way.

If Congress wants to help get this country energy-independent, to encourage the natural gas and oil production which we need to accomplish that goal, then we cannot afford to undo the tax relief and incentives that we have in place. If it is in the best interests of our national security and the viability of our domestic industry to do that, then I think that we have to look seriously at leaving in place those types of incentives.

Around this country and particularly in the State of Oklahoma, as Jim pointed out, we have a depressed economy when it comes to energy. Our royalty owners have suffered enough. Our independent producers have suffered enough. If we truly want to accomplish the goal of becoming energy-independent and having the type of energy production which will make us energy-independent, then we should not undo those tax incentives which have helped accomplish the goal of making us energy-independent.

Thank you.

[The prepared statement follows:]

### STATEMENT OF HON. MIKE SYNAR, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF OKLAHOMA

Mr. Chairman, I'm happy to appear here today with my colleagues from Oklahoma. I appreciate you allowing the dean of our Delegation, Jim Jones, to testify on our behalf.

I would simply like to lend my fullest support to Congressman Jones' remarks. I'd like to re-emphasize two points which Jim made here today. First, the energy industry in Oklahoma and around the country is in a seriously depressed state and may be for some time. I might add that, as a result of this, thousands of royalty owners in the state have suffered financially as well. Second, I would reemphasize that the energy industry and royalty owners are already heavily taxed at the federal and state level—in spite of the tax incentives under review here today.

If we in Congress want to continue to encourage domestic oil and gas exploration and production—and I believe we do—then I would urge the Committee not to "undo" those tax incentives currently in place which encourage exploration. They are crucial to much-needed industry investment and to a continued viable domestic energy industry.

Thank you again, Mr. Chairman, for the opportunity to comment here today.

## STATEMENT OF HON. WES WATKINS, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF OKLAHOMA

Mr. WATKINS. I would like to thank you for allowing us to come with a united front from Oklahoma. I want to thank my colleagues for also allowing me to appear with them.

I would like to make an impression on the committee that even though Oklahoma is an oil industry State, it is not synonymous with wealth throughout the State of Oklahoma.

I would like to point out that in my district, I have counties that have 21-percent unemployment, several of them in the 18-percent bracket.

The Chicago Sun Times just did a survey on the wealth of congressional districts with No. 1 being the wealthiest and the 435th Congressional District being the poorest.

My congressional district lands 423d, or 12th, from the bottom as far as wealth goes, with only 1.6 percent of the homes above $100,000 in value.

I want to point this out, because the unemployment, the income throughout the State has dropped tremendously. In fact, I could only compare it, Mr. Chairman, with the drop in the prices of oil and also the taxes that we have had placed on us in the past.

We have suffered a greater loss to the treasury in Oklahoma than proposition 13. And I think we understand what has happened to education. And you may wonder what is synonymous with the prices and taxes on oil, with the handicapped children in the far eastern part of my State. In Oklahoma, there is a direct correlation of what kind of revenues can be there to help the children and the elderly of our State of Oklahoma.

I would like to point out one other quick fact, and that is the small independent producers have had a record of returning into the ground in wildcat production of 105 percent of their earnings. And what that means, Mr. Chairman, they have gone out there and borrowed money in order to try to produce in this country the needed energy and oil. And with the tremendous drop in the oil price and the taxes on top of it, we have more bankruptcies in the oil business in Oklahoma than any other time in the history of our great State since 1907.

So, Mr. Chairman, not all is well with the oil industry in the State of Oklahoma. We have our ills and side effects.

Hopefully, if we can have the right type of structure, we can rebound and bring back a healthy situation to the economy, not only in the State of Oklahoma, but in many other States across this Nation of ours that have the responsibility and task of producing energy for the entire United States.

## STATEMENT OF HON. DAVE McCURDY, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF OKLAHOMA

Mr. McCurdy. Mr. Chairman, members of the committee, I want to express my appreciation for the opportunity to testify this morning. I want to associate myself fully with the joint statement just made by the distinguished dean of our delegation, Congressman Jones.

I would like to very briefly emphasize the seriousness of the present situation in Oklahoma.

In February 1982, 112,400 Oklahomans were employed in the oil and gas business. In February of this year, there were only 83,100 jobs, a drop of more than 25 percent. One year ago, in my district, Halliburton had 4,600 employees. Today, they have 3,500. In Stephens and Carter Counties, in South Central Oklahoma, unemployment is above 9 percent; 85 to 90 percent is directly attributable to the downturn in the oil and gas business.

The same is true in Grady County, where unemployment now stands at 11 percent.

Bear in mind, this is an area where until very recently unemployment has been in the 1.9 to 3.5 percent range. Unlike the big integrated companies, which deal in finished products, the small, independent producer has only one source of income, the sale of raw crude. If we tax away his profits, we will soon find ourselves without a domestic source of crude oil.

The impact will be felt not only in the oil and gas industry, not only in the producing States, but throughout the entire nation.

Mr. Jones. Mr. Edwards?

## STATEMENT OF HON. MICKEY EDWARDS, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF OKLAHOMA

Mr. Edwards. Mr. Chairman, first, thank you for giving us this time to be heard as a delegation. The dean of the delegation, Jim Jones, spoke for us very well. We are unified on this issue. It is something that affects our whole State.

Let me just make two or three points pretty quickly.

First of all, the energy industry is heavily taxed. The windfall profits tax alone in the last 3 years has brought in from producing companies and royalty owners well in excess of $40 billion, nearly $50 billion. There are many taxes that affect the oil industry. I think you would be hard-pressed to say that the people in the energy-producing industries don't pay their fair share of taxes. I think you could argue that they pay well beyond their fair share of taxes.

Dave McCurdy made some comments about the state of the economy in Oklahoma, as did Wes Watkins.

I know of one office building in Oklahoma City where on one floor of one building four different oil companies have gone out of business in the last 6 months. And that has a second side to that point, too: The people who produce this energy, the people who produce most of it, are not the Exxons and the Mobils of the world, but a lot of small independents. They are small companies. It is a high-risk, very speculative business. Dry holes outnumber wells that produce by as much as 10 to 20 to 1. But there is a great deal of investment capital that has to go into even a well that turns out to be dry.

Let me make one final point.

I serve on the Appropriations Committee. On that committee I am on the Subcommittee on Military Construction, and on Foreign Operations. I am very much aware, and I think many Members of Congress are aware, of the absolute security need we have in this country not to increase our dependence on outside suppliers. Even with the increase in our own domestic production, we still depend on OPEC for 40 percent of the free world's daily crude.

The Soviets have now completed or are in the process of completing a pipeline which will make Europe more dependent. We cannot afford for our own national security purposes to let ourselves remain continually dependent on outside sources for our energy.

We have to do those things that encourage our domestic energy producers to be able to increase their production and increase the security of this country by doing that.

Mr. JONES. Mr. English.

## STATEMENT OF HON. GLENN ENGLISH, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF OKLAHOMA

Mr. ENGLISH. Thank you very much, Mr. Chairman. I certainly want to commend you for holding these hearings and giving us the opportunity to tell you the difficulties of the oil and gas industry. They are facing some very big difficulties these days.

My district is an agricultural district, most of western Oklahoma. It is the third largest wheat-producing district in this Nation. I think most people understand and recognize that today agriculture is in a genuine depression, not a recession, but a depression.

The oil and gas activity over the past 3 or 4 years has enabled many of our farmers to stay in business that would no longer be there. But the oil and gas industry has fallen on hard times as well.

In my district, we have what is known as the Anadarko Basin, where the gas wildcatters of this Nation search for some of the deepest gas in the world. The activity in that area has provided jobs not only for the people in western Oklahoma, but from throughout the United States. Stories in newspapers and magazines and on television about the jobs that were available in western Oklahoma, when recession was occurring elsewhere, brought in thousands of people in search of jobs.

One year ago, in my home county, which is a part of the Anadarko Basin, Mr. Chairman, the unemployment rate was 3 percent. That same county today faces an unemployment rate of over 12 percent, and it is still growing.

It shows the depths of the difficulties that are facing that area, not only due to agriculture, but due to the problems of the oil and gas industry.

And I think that unfortunately the press has focused its attention on a few eccentrics, and every industry has a few political eccentrics, but I think we must point out that the oil and gas industry is made up of literally thousands of individuals who are living paycheck-to-paycheck, the same as every other industry in every other part of the country. So I would urge, Mr. Chairman, that you provide whatever assistance and relief that you can to assist this industry to get underway and provide the jobs and economic recovery that our Nation needs.

Thank you, Mr. Chairman.

Chairman RANGEL. On behalf of the full committee, and certainly our subcommittee, we thank you for the testimony that you have given us today. It will be very, very helpful to us in our preparation for our report to the full committee.

Are there any questions?

Mr. Duncan.

Mr. DUNCAN. I would like to thank our colleagues. I think they are well versed in this particular industry, on this very important subject.

You touched upon the royalty fees being paid to various individuals. Are some of those people having a somewhat difficult time now because of the lower production of gas and oil?

Mr. ENGLISH. I assume you are directing the question to me.

Mr. DUNCAN. You mentioned it.

Mr. ENGLISH. I don't think it is from overproduction. The difficulty that we have had, quite frankly, is the transportation of those products out of that area. There has been a great deal of natural gas in the Anadarko Basin that has been discovered that simply has no way to move at this point.

The pipeline capacity simply is not there. They are not tied into those pipelines. I had one individual that I am very close to in the industry who was talking to me about his problems. He said we have talked to users in other States, and we have shown them that we can provide natural gas considerably cheaper than what they are buying at the present time. But our difficulty is that we cannot get it to them.

I think that they would certainly like to have that opportunity. But so far as the royalty owners, most of them simply have their minerals leased; those are usually short-term leases, 2 or 3 years. It has been that extra money that has enabled many of the royalty owners, particularly farmers, to make payments on their loans and stay in business.

Mr. DUNCAN. Do all of you think the tax treatment of different types of producers within the same industry should vary? Do you have any thoughts on that?

Mr. SYNAR. That issue is what we are looking at in Energy and Commerce right now, with the whole question of decontrol of natural gas, and whether or not there should be a tier system. I speak on behalf of the Oklahoma delegation, I think, in the sense that in a perfect world, we all believe that the free market system is the way to determine the price of any commodity, including energy. And I think we have found, through the decontrol of oil, that it will seek its own level, and we will get benefits.

We are in some unique circumstances presently, because we have had an industry that has been created because of the Natural Gas Policy Act of 1978. So, as we look at the question of transportation, pipelines, as well as the need to continue incentives for production, as well as protect consumers in an effort to fight off high utility bills, we face in Energy and Commerce the practical problem of how do we get to the solution of free market system without hurting both ends of the market.

Mr. JONES. I think, Mr. Duncan, we would be unified in saying the differing tax treatment, as it now exists between independents and the integrated companies, is one we do support.

Mr. DUNCAN. Thank you very much.

Chairman RANGEL. Mr. Pickle?

Mr. PICKLE. Mr. Chairman, thank you.

I want to commend the Oklahoma delegation for its testimony, the unified presentation of valuable facts.

Your statement, Mr. Jones, was very helpful. You are a very valuable member of this committee and of the Congress.

For record purposes—can any of you give me an estimate of the number of rigs that are down now in Oklahoma compared to, say, 3 years ago?

Mr. JONES. We can tell you that. As we said in our prepared statement, from 1 year ago it has dropped about 71 percent. One year ago, there were 788 active rigs; today, there are 232, a drop of 71 percent.

As I recall, 2 years ago, or 3 years ago, the active rate count was between 900 and 1,000. So, it is a greater drop over that 2-year period of time.

Mr. PICKLE. But there has been a tremendous drop. The same thing applies in my State.

Mr. JONES. Nationally, the domestic industry has dropped from about 4,500 rigs to about 1,800 rigs. So that is quite a drop.

Mr. PICKLE. Those facts are very meaningful. The price of oil, from, say, 3 years ago, has dropped from what level? What level is it now?

Mr. WATKINS. It averaged approximately $38 a barrel last year, but it has dropped all the way to about $28 to $29, somewhere, now. So you can see what kind of drop there is. For each dollar it drops, you can estimate close to 1,000 stripper wells going.

Mr. PICKLE. Mr. Jones, let me ask you this: Would you mind telling to us just why the depletion allowance is important to the independent producer?

Mr. JONES. Mr. Pickle, the concept of depletion stems from the view that certain materials are of limited supply, and those engaged in the business of extracting and selling those materials should be compensated for the reduced value of the holding.

It is particularly important to independents. We have seen in the past, for example, in 1970, when the depletion allowance was dropped from 27½ percent to 22 percent, there was an immediate drop of about 2,000 wildcat rigs that year.

The industry really did not recover from that until 1977. As I mentioned in the opening statement, right now, raising capital for the risky ventures of oil drilling is very, very difficult, particularly in Oklahoma, because of the bank failure and just a general uncertainty that exists there.

Without these kinds of incentives, such as depletion allowance, and particularly the IDC's, the intangible drilling cost deduction, I just don't believe you could raise the kind of capital that is necessary to put a deal together to drill that hole in the ground.

Why would someone who could get the advantage of accelerated depreciation, et cetera, by buying into a K Mart building, or something like that, why would he take the risk without any kind of tax incentives and drill a hole in the ground several hundred feet down?

So, the primary importance of the depletion allowance and the IDC is the attraction of capital. And for the independents, they have no source of capital like the integrated companies do. They don't generate internally the kind of capital that is required for these very expensive drillings.

So, that is why it is important.

Mr. Edwards. If I can add something to that—I am not sure how it is in Texas, but in Oklahoma we have a lot of stripper wells. We have a lot of very expensive production. When you have independents who are going after secondary recovery, tertiary recovery, trying to get the last drops out of a diminishing reservoir, I think you understand it is difficult sometimes to get the kind of capital that you need to go after this very, very expensive form of production.

I think if I would leave the committee with any thought, it would be to understand, and it is probably the same in Texas, that it is really not major companies that are producing this energy we are talking about; it is pretty small independents who are out having to scrounge around to get somebody to give them some capital to drill on a risky business venture.

Mr. Pickle. Thank you.

Mr. McCurdy.

Mr. McCurdy. Mr. Pickle, I wanted to elaborate on just one point, if I might. I think it is important for members to remember that within this delegation—there are six of us—there is represented a wide range of diverse, different types of oil and gas production in each of our districts. My district, for instance, is very similar to Congressman English's in that we share the deep Anadarko Basin, where we are having exploration at 23,000 feet down.

We are talking about investments of $8 to $10 million per well. In order to accrue the capital necessary to make that kind of investment, you need to have some real tax incentives for investors who want to take that potential risk, which is so much greater than it is at a 2,000- or 3,000-foot depth.

So, we are at the leading edge of technology; we are at the leading edge of exploration in this area. And because of the depressed prices and uncertainty in getting capital investment, we have had a tremendous decline in our economy. People think of an oil well as a solitary unit out there, but it is the ancillary business, the support structure—the pipe companies, the contractors—that have been hit the hardest in this area.

So, when you have one well go down, it has a very widespread effect on the entire economy in our State.

Mr. **Jones**. Mr. Chairman, could I just interrupt you a minute?

Our senior Senator from Oklahoma, David Boren, is here now, also, and could join the delegation. He serves on the Senate Finance Committee, as you know, and Senate Agriculture Committee.

With your permission, we would like to ask him to join our delegation.

Chairman **Rangel**. It is altogether fitting and proper that we hear from the senior Senator from Oklahoma. The committee welcomes Senator David Boren.

Senator, we welcome your contribution. You may proceed.

## STATEMENT OF HON. DAVID L. BOREN, A U.S. SENATOR FROM THE STATE OF OKLAHOMA

Senator **Boren**. Thank you very much, Mr. Chairman. I am very proud to join with the other members of the Oklahoma delegation in presenting this testimony to you today. Just having heard a portion of what my colleagues from Oklahoma have said, I want to emphasize the desperate situation that we are in.

We just concluded a meeting in my office this morning, at which it was estimated that as of the end of this past year, we were only selling in Oklahoma 39 percent of the allowable gas production that is available from that State. And it was estimated that that figure today is probably less than one-third. That means that we have had about a $2 billion drop in income to producers, principally independent producers, who are experiencing the shutting in of gas just since the first of this year. In a State of 3 million people, a relatively small State in population terms, I think you can see the impact of that kind of decline.

As Congressman Jones has just pointed out, in response to Mr. Pickle's question, we have stacked in Oklahoma now more than 600 drilling rigs. At our peak, we crossed the 900 level in terms of the number of drilling rigs operating in the State of Oklahoma. This week, we are at the level of 243 now operating.

Mr. Chairman, you can drive up and down the highways of the State of Oklahoma and see them stacked up and down the sides of the roadway in yards.

Many of those drilling rigs were built new over the last 2 or 3 years, since we have had the upswing and the incentives, much of it due to the incentives which we provided to the independent producers, and most of them were built by independent producers with borrowed money. They range in cost anywhere from $1 to $10 million each, depending on the size of those rigs. And I would say they would average out somewhere between $3 and $4 million.

When you think about the fact that these people borrowed money at approximately 15 percent, some of them higher, for a $3 or $4 million drilling rig, and there are 600 of them stacked in the State of Oklahoma today, with no cashflow coming in, I think you can see the kind of terrible credit squeeze and cash flow squeeze that the independent production sector is experiencing. It is translating itself into the highest bankruptcy rate that we have had in the State of Oklahoma on record for the first 4 months of this year.

I would go back to the point that has been made already. There is little doubt that independent producers are treated differently in the Tax Code than our major integrated oil companies. But the difference in treatment for the small domestic companies is justified. They have ploughed back more than 100 percent of their wellhead revenues from both crude oil and natural gas production. Independent producers are accounting for 89 percent of the wildcat wells and 75 percent of the new fields found.

So, it really boils down to this: We are experiencing, without exaggerating the seriousness, a depreciation in the independent production sector of this country. If we allow it to go on, particularly if we were to take any action which would make it worse, at this very devastating time for us, all we would be doing is dismantling a portion of that domestic industry. It would be very hard to bring it back. We would be building in shortages of domestic energy for ourselves in the future, and again cyclically causing the kinds of problems with shortages and high prices for consumers that we have experienced in the past.

I understand that there are some frustrations with some of us. As a Democrat, I can understand there is some frustration with some independent producers. But I think we have to be very, very careful that we do not allow any political differences that we might have with some of them in terms of their own political philosophies to lead us to make changes in the tax law for those producers who are just barely hanging on and risks damaging our Nation's domestic energy sectore.

So, I would urge the committee to look at the facts. Look very carefully at what is happening to the independent sector right now, in terms of the devastating effects that we are feeling, and to also remember that if we do let the domestic independent industry decline, it will be harder to bring it back.

It is not like turning a water hydrant on and off. The major integrated oil companies could take up some of the slack, but their focus is not on new exploration and production. Shortages could occur, and also we must remember that the loss of competition from the independent sector with the major companies is bound to cause higher prices for the consumers in the future if we allow the decimation of the independent sector.

I do have a full statement, Mr. Chairman, and I would like to ask consent to insert the full statement in the record. But I am very pleased to be a part of a united effort by the Oklahoma delegation.

I want to commend Congressman Jones and my other colleagues from Oklahoma for making this effort, and am proud to be a part of it.

Chairman RANGEL. Thank you, Senator. Your full statement, without objection, will be entered into the record. We on the committee would like to thank our cocommittee member, Chairman

Jones, and the entire Oklahoma delegation for the contribution that you have made to these hearings. I want to assure you that your testimony, your feelings, and your expertise certainly will be taken into account as we make our report to the full committee.

[The prepared statement follows:]

### STATEMENT OF HON. DAVID L. BOREN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF OKLAHOMA

Mr. Chairman and members of the subcommittee, I want to thank you for the opportunity to speak today on a subject that is of vital importance to this nation's continued energy independence.

There can be little doubt that independent producers are treated differently in the tax code than are major integrated oil companies, but the different treatment these small domestic companies receive is justified. Independent producers have historically plowed back over 100 percent of their wellhead revenues from both crude oil and natural gas production into more exploration, drilling and production activities.

During the last ten years, independent producers have accounted for 89 percent of the wildcat wells drilled, 75 percent of the new fields found, and 54 percent of the total oil and gas discovered. Independent producers derive their income from this one activity. Any capital loss resulting from increased taxation means fewer wells will be drilled.

Another important reason for special treatment of independents is that it is much harder for them to comply with the tidal wave of complex crude oil and gas tax regulations. They do not have the battalions of accountants and lawyers employed by major integrated companies because the cost is so prohibitive. Compliance with all the current rules has already diverted substantial drilling revenues into administrative overhead expenses, further reducing an independent's ability to compete.

Now, more than ever, independents need the extra incentives that these lower rates provide. The cost of drilling an average well has risen over 350 percent since 1970. It is currently costing close to an average of $400,000 per well. To drill the deep gas wells of western Oklahoma, it can easily cost $10 million per well. At the same time, the price of crude oil has declined dramatically due to decreased demand. The decrease can be attributed to consumer conservation and the worldwide recession.

As if soft prices and increased drilling costs are not enough, the situation has been exacerbated by tightened credit restrictions throughout the Southwest. At the height of the drilling boom brought on by the decontrol of oil, independent producers were able to borrow on projected discoveries until wells came in and were put on line. The collapse of the Penn Square Bank in Oklahoma City, however, drastically tightened the credit available to independent producers throughout the Southwest.

This, in turn, has precipitated a massive rise in the number of bankruptcies among independent oilmen and their support industries. Within Oklahoma, bankruptcies rose by 14 percent in 1982, missing a record for such filings by 98 petitions. During the first month of 1983, statistics show bankruptcy filings up 30 percent over January of 1982. There were over 60 filings with many more expected as the year progresses. The Oklahoma bankruptcy court attributes these dramatically increased figures to the oil and gas industry, which has been filing as exploration, production, drilling, welding, dozer, trucking, and pipeline companies. They are literally struggling for their survival.

These bankruptcy petitions filed by those businesses which serve the oil and gas industry point to the fact that many non-energy sectors of the Oklahoma economy are directly linked to the performance of its energy sector. In fact, a study published in the April, 1982, edition of the "Regional Review of Economics and Business" attempts to empirically quantify these linkages. It concludes that Oklahoma's overall economic wellbeing is heavily linked to the performance of its energy sector. The rate of unemployment in Oklahoma has currently risen to 8.8 percent. Our normal unemployment rate has been 3 percent. Since our state economy tends to lag behind the national economy, we can expect little improvement in our rate of unemployment for the rest of 1983. In terms of the effects it would have on an already depressed Oklahoma economy, a revision or repeal of the incentives provided independent producers can be ill afforded at this time.

Another indication of the sorry state of oil and gas economy at present is the rig count. The number of active drilling rigs continued to drop in Oklahoma last week, falling to 232. This is 70 percent decrease over last year which was 788. A year ago the country had 3,310 rigs drilling, while at present there are only 1,860 active rigs.

I think the rig count demonstrates that Oklahoma's situation is not unique. The depression in the domestic energy industry has spread to all the producing states. The loss of these independents due to this crisis could force Americans to have to again depend on the whims of a few large companies for our energy supplies, as before the Arab oil embargo of 1975. We should be talking about how we can protect our domestic suppliers, not how we can further reduce their ranks.

As a Democrat, I can understand the frustration of Members with some of the independent producers. But we cannot allow partisan politics to get in the way of sound energy policy. To talk of changing the tax treatment of these producers who are now just barely hanging on is misguided and risks damaging our nation's domestic energy security. The independent producer is an individual just like you and me, with his own loyalties and political philosophy. They shouldn't be declared unfit for specialized treatment because one disagrees with their philosophy on a given subject. Their tax treatment certainly should not be based on their political philosophy but on the country's need for their continued service and viability. I for one believe that their competition has been healthy and is in the best interests of the consumer in maintaining a fair and equitable price for the product.

I hope the testimony that will be given here will help you to understand the important role that the independent producer has and continues to play. If the domestic industry is allowed to decline due to changes in tax treatment, it will be harder and harder to bring it back. It is not as easy as turning a water hydrant off and on. The major integrated companies may take up some of the slack, but their focus is not on new exploration and production, so shortages could occur in our domestic supplies. In addition, the loss of competition from independents is bound to cause higher prices for consumers. In short, maintaining the status quo for independents may allow some of them to survive the current crisis, but eliminating such incentives, may pull down the rest of the industry. They are fighting for their life right now. Eliminating this segment of the industry would be a real blow to the U.S. energy security.

Thank you again for the opportunity to speak on this crucial issue.

Mr. JONES. Thank you, Mr. Chairman.

Mr. MCCURDY. Mr. Chairman, I would like to extend an invitation to any of the committee members who want to see first hand the exploration in our part of the country. I know some members have taken advantage of this already. I think they find it very enlightening to see actual production.

Chairman RANGEL. Before all of the delegation leaves, some of the members may have questions. Also, I would ask Mr. Pickle to chair the meeting. I have some constituents that are suffering some hardships in the area of public housing in New York who I would like to chat with.

Mr. PICKLE. Mr. Chairman, I thank you for the invitation. I have constituents to see also.

Mr. ANTHONY. My constituents are suffering so much they could not come up here.

Mr. CAMPBELL. Would the new Mr. Chairman recognize me?

Mr. ANTHONY. As long as I have the gavel, I think I will have the perogative to get my questioning in first, Mr. Campbell.

I was really intrigued by the comments made by English and also Senator Boren.

Although we did put out a press release stating what the purpose of the hearing was, there were rumors that there were some ulterior motives for the hearing. Regardless, I would like to just publicly say that I admire and respect the entire Oklahoma delegation, the fact that you have come here and laid aside any political differences that you may have.

Also, I think it shows that you are here to represent the best interests of a segment of an industry and the average citizen in the

State of Oklahoma, who benefit from the industry and the revenues generated by that industry. And rather than calling you politicans, I should just call you statesmen. I think you have made a valuable contribution to the committee.

Mr. Campbell, with that glowing recommendation of the Oklahoma delegation, I yield to you and then to Mr. Pickle.

Mr. CAMPBELL. Thank you.

First I, too, want to thank the Oklahoma delegation. I think it is very commendable, what you have done. I was interested in one side comment that had nothing to do with the substance of the issue, but may have to do a great deal with why we are holding the hearings. That was some reference to political activities of a few eccentrics, or one or two individuals or a group of individuals.

I understand that feeling. I represent an area that has a very large industry, it happens to be Texas. I, too, have had contributions and support given to opponents from that industry. I shall still try to stand with my constituents and their jobs and not let that sort of pettiness interfere. I commend you for it.

Let me ask this question, either of Mr. Jones or Senator Boren.

Of the companies that produce, say, 10,000 barrels a day or less, do you think it would be a significant factor if we did away with the depletion allowance on that first 1,000 barrels.

Do you think it would impact them adversely to the extent that they would curtail their exploration?

Mr. JONES. From my own perspective, and this is peculiar to Oklahoma at the present time, I think it would have a very negative impact on their drilling activities. I think it would have a very adverse impact on their ability to raise the capital to take that risk.

How you quantify it, I don't know. But I think you would see a further great depression in this segment of the industry.

Mr. CAMPBELL. And the same would hold true for the write-off of intangible drilling costs?

Mr. JONES. Perhaps even more so on the IDC's.

Mr. CAMPBELL. I am very interested. I am looking at the testimony given earlier by the CBO.

It appears from this that 65 percent of the oil companies listed in the country fall into that category of those that produce less than 10,000 barrels a day. In fact, if this committee is here for the purpose of trying to make changes, then it seems we are trying to destroy the small producer in the industry. Is that not a correct statement?

Mr. JONES. I think there is no question about it. You are absolutely on target on that statement. And this segment that comprises 65 percent of the industry that you talk about is shrinking fast. In my own district, the number of bankruptcies filed by companies of this size is just staggering.

Mr. CAMPBELL. I am deeply concerned about it. I don't ever want to see us get to the point in the country where we destroy the smaller business people to the benefit of the major large companies. Each has a purpose, each serves a role. But the competition that is created and the energy that is discovered by these smaller companies is, I think, one of the most important things we can deal with, not only for the national defense, but for the economic system itself.

Senator **Boren**. Mr. Campbell, if I might add—the impact on the long-term productive capacity might even be greater than you might think from looking at the 65-percent figure because, as we pointed out, the vast majority of the wildcats, the new discoverers, people going out and really taking the plunge, this is done by the independent sector, the smaller producers. Most of them operate on borrowed money.

The major companies come in and develop those new fields once they have been discovered by the independents. So the long-term impact on reduced domestic production could be even more severe than what might appear from a first glance at the statistics. And we cannot overemphasize what is happening as a result.

In our State, for example, the Penn Square Bank collapse—some $1 billion of credit after the energy sector was suddenly cut off, that meant that one company that had money in the bank was not able to pay another. There was a true domino effect.

There has also been a tendency to overreact on the part of those who are now conducting the bank examinations, they want to be careful that that doesn't happen again. So if anything there is an overscrutiny now of energy loans. There is a retrenchment in terms of the willingness of other financial institutions, really beyond what is reasonable or prudent, to reduce the amount of credit available. And so when you talk about the combined effect of reducing, where you are talking about intangibles, or depletion, or independent stripper reduction, you are just really cutting back on what little cash flow it is possible for the independents to flow back.

When you have an industry plowing back 100 percent, this means you can add up the dollars of tax benefit and say there is going to be that much less money, not only that much less, but that much less plus what can be leveraged to borrow against it as well that is going to be spent on domestic production, and in the long run you are creating a problem for the consumers.

Mr. **Watkins**. Mr. Campbell—in Oklahoma, 90 percent of the wells produce 10 barrels or less, are stripper wells or less. So you can see that is a small industry to say the least, compared to the figures that you were using there also, and what effect it would have.

Mr. **Edwards**. Let me add something.

The gentleman from South Carolina has hit a very important point. We have all emphasized the nature of the energy-producing industry in our State If tax changes are made, for example, on the intangible drilling cost field, what you will end up with is a few very large companies and OPEC providing the energy sources for his country. And we will be putting a small business—I know the gentleman from South Carolina has an interest in preserving small business—we will be putting a small business essentially out of business. And it would be disastrous for a lot of reasons.

Mr. **Campbell**. I thank the gentleman.

I am not going to take any more time other than to say this: I was looking at the list of the publicly held corporations that are in the oil business by size of production. That is where I got the 65-percent figure which were under 10,000 barrels per day.

It is interesting to note that 28 of them produce less than 100 barrels a day; 41 of them produce less than 500 barrels a day. If you carried it up to 20,000, then you have a much higher figure. 182 of the companies produce less than 20,000 barrels a day out of the total 240 companies. So, we are talking about going after a majority of an industry that is wildcatting, making the new discoveries, who represent the small investor. The results of it, in my opinion from the testimony that we have had, seem to support the fact that it would be devastating to our economy and our energy policy of this country.

I thank you for coming before us.

Mr. ANTHONY. Mr. Pickle.

Mr. PICKLE. Senator Boren and members of the Oklahoma delegation, again I want to thank you for your presentation.

First, Mr. Chairman, based on what Mr. Campbell said at the beginning of his statement—that the purpose of the hearing might be to make some changes in the oil and gas laws that could be detrimental to independent producers—I take it the Chairman's statement earlier this morning means that we are trying to make the record. This committee is not here for the purpose of making recommended changes, but rather to make a record, to show why there is a differentiation in tax incentives.

I don't think anybody questions there is this differentiation. Earlier this morning Dr. Rivlin testified that in some cases the independents' cost of oil would be cheaper than that of the integrated companies.

She gave three examples—wells No. 1, which was a new field, well No. 2 was a field in an existing field that had become a stripper after 5 years, and well No. 3 was a well in an existing field.

Those facts may be correct, but nowhere did she pay account to the fact that there also can be dry holes. Dr. Rivlin mentioned three cases of successful operation. She doesn't mention those dry holes, about 8 out of 10 for independents. Who pays for that? Independents don't have downstream activities to ease the cost of dry holes.

A lot of people think independents punch a hole in the ground and make so much money that they deserve to be taxed high. But the critics don't say what happens when you hit a dry hole. It is not always honey and cream, or oil. Sometimes it is bankruptcy. So, independents do have the risks. We are trying to show in these hearings that a difference between independents and integrated oil producers do exist and there is a reason for it.

Earlier the Chairman asked why independent producers should get an extra tax incentive. He asked if there is any other industry that gets that extra break. The fact is that the question wasn't answered, but let me ask this question: Do any of you gentlemen know of any tax the Congress has ever levied against one single industry—the oil and gas industry—so onerous as the windfall profits? You men are experienced. Can you remember any time when the Congress has singled out a single industry to tax with such a burdensome tax?

So, we have this tax. We have accepted it, not happily, but we try to make the best of it.

The economic turn of events has been such now that we have to concern ourselves with recovery, and not whether we need changes made in the tax laws. This committee is not trying to be negative about it. We want to make the record. That is what we are trying to do. To that extent, it is perfectly proper that we do it. And I welcome it.

I thank you for your statement.

Mr. ANTHONY. Mr. Thomas.

Mr. THOMAS. I thank the Chairman. I have some statements and some questions.

I am very supportive and appreciative of my colleague from Texas indication of the direction of this hearing. My opening remarks were somewhat critical of the material that had been provided. As I reviewed various suggested questions for various panels that were going to come up, I came across questions that started out: "To what extent did the special tax breaks," et cetera; "is there any justification for," et cetera, another good one—"even with the imposition of the windfall profit tax, all producers have benefited by decontrol and the huge rise in prices," et cetera, et cetera.

So, I am very grateful for the clarification from the gentleman from Texas that the purpose of this hearing is to make a record to indicate why independent producers have differential tax procedures rather than an attempt to determine where we should take it away.

I am especially grateful to the Oklahoma delegation. I happen to represent a county in California which produces approximately the same amount of oil as the State of Oklahoma. And I want to say that the statements that you have made I agree with heartily. You have done it qualitatively and quantitatively better than I could have.

I want to commend the Senator for his indication that price is a factor, but psychology is as well. And we currently have a price out there that is not very good in relation to recent prices which produces a psychology which increases the direction of parked rigs.

Also, I want to commend the Oklahoma delegation for pointing out once again, far better than I could, that oil is something other than a revenue source to government. It is jobs. It is energy for America's industry and agriculture, power and light for transportation, and it is, as Mr. Edwards said, security.

In addition, I want to compliment Mr. McCurdy for his indication that when we talk about oil, and we talk about producers and talk about taxes, there are a large number of people who are dependent upon the fellow we talk about being a producer. Ancillary industries are significant. And when the producer is affected, the whole industry is affected in the way in which oil operates, whole communities are affected. As you have indicated, whole States are affected.

I want to compliment you on your testimony. Thank you.

Mr. JONES. Mr. Chairman, could I make two observations at this point?

Mr. Thomas represents a great oil-producing area also. He probably also represents as many native Oklahomans as any of us do. We hope that experience won't happen again as it did about 50 years ago.

A second observation that just struck me as we were here, is that we have as much unity on this issue in the Oklahoma congressional delegation as there is unity on every issue in the North Dakota delegation represented by Mr. Dorgan.

Mr. **Anthony**. Mr. Dorgan.

Mr. **Edwards**. May I make an additional comment on what Mr. Thomas said?

I think a point that you picked up on in our testimony was very important. That is the ramifications behind the producing companies, the point Mr. McCurdy made, about the ancillary companies.

My son-in-law is unemployed. He has been unemployed for 2 months. He works for a pipeline inspection company which has gone out of business. The effect is not just with those companies large or small which go out and produce, but as you observed, and Mr. McCurdy pointed out, the effect spreads all through a State like our own, and I am sure all through your county, where there is so much dependence of the whole economy on the oil and gas industry.

Mr. **Anthony**. Mr. Dorgan?

Mr. **Dorgan**. Thank you, Mr. Chairman.

Speaking as the dean of the North Dakota delegation here in the U.S. Congress, a delegation of one, I just have a couple of quick comments.

I know that you folks have spent a lot of time with us this morning. We appreciate that.

First of all, I expect a lot of people from the oil industry think that supporting the windfall profit tax is like being a public relations man with polio.

I do think the windfall profit tax, when it was developed, was done because there was an artificial market that existed for oil, an artificial price. It had no relationship to cost. It went from $3 to $38. If you let the price of oil rise to the OPEC price, what do you do with the incredible profits that are generated. They tried to come up with a windfall profit tax, part of which was designed in a way to encourage reinvestment.

If I might focus on just a couple of things, I think Senator Boren indicated competition here is important. That really is my interest as well.

North Dakota ranks about ninth in the country in oil production. My interest is in preserving competition, so that independents who spend the money to go out and look for oil can continue to compete.

Mr. Thomas pointed out the bottom line is where it is at when you make judgments about what you are going to do. The bottom line certainly is affected by taxes. By far the biggest incentive affecting the bottom line at the moment is price. It completely overwhelms the tax question at the present time.

But the tax impact does make a difference in investment decisions. I understand that. My interests and the interests of many others on the committee is to make sure that we have a network of independent producers out there that have sufficient incentive to go looking for oil.

The comment Mr. Synar made about independents is still important. People have forgotten about the need for us to look for ways to become independent of those overseas who would affect our energy future. If the royal family in Saudi Arabia is deposed or something happens, tomorrow this country is going to be in a fix. We are going to start talking about our energy shortage again.

I think what you have said is very important. The point Mr. Jones made is something I want to explore in these hearings.

The Oklahoma delegation pointed out that studies show that reinvestment by independents is 105 percent. I think it was Mr. Watkins. I am hoping we can develop a dialog around that point, because that really is the goal, to try and figure out how you encourage reinvestment. I am not interested in giving anybody special tax incentives to go out and buy something else. I am interested in special incentives to people who will look for more oil.

My concern about some majors in this country that have developed some capital and went over and bought something else with it is a concern that we can deal with another time.

The question of reinvestment of the independents is a very important one. I appreciate Mr. Watkins raising that issue.

Mr. WATKINS. One of the things we were trying to do at that time was to get decontrol with a plowback provision in order to increase the production of independents in this country. But the tax increased—the popularity of the tax for the funding of government won out.

Mr. DORGAN. One other comment.

The question is, what is independent? We do have some mom-and-pop independents that are half-a-million-dollar outfits. Nothing wrong with that. We have to analyze here who is getting the benefits and what are they doing with them. Is it really in the best public policy interest to proceed the way we are or change it?

There is no hidden agenda I know of. I am very interested in these things.

Thank you.

Chairman RANGEL. Thank you again.

We have Congressman Glickman.

I see Congressman Bill Archer has joined with us.

We welcome your presence to our hearing room.

## STATEMENT OF HON. DAN GLICKMAN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF KANSAS

Mr. GLICKMAN. Mr. Chairman, I will try to take no more than 2 minutes. I ask unanimous consent my statement appear in the record.

Mr. Chairman, I would echo many of the remarks that were made by the Oklahoma delegation, but just bring to your attention that Kansas is truly a State that virtually has no major oil companies at all. It is slightly different than Oklahoma. It is almost exclusively an independent State.

Mr. Thomas said 65 percent of all oil is produced by companies with 10,000 barrels or less per year. I doubt if we have five independents in the State of Kansas that produce 10,000 barrels.

We are really, in terms of the per-well situation, small potatoes. But we have lots and lots and lots of them, lots and lots of mom and pops. The situation in Kansas is similar to what it is in Oklahoma. We have about 55-percent decline in drilling rigs working. Part of that is due to the recession, clearly.

People are using less energy. But the fact of the matter is that it has caused some degree of unemployment in the industry. The independents have some preferential benefits under the law that major oil companies do not have with respect to windfall profit tax, with respect to percentage depletion, and the individual coal oil and gas producers do have intangible drilling costs as well.

For the most part, independents reinvest all of their income into oil and gas production. They don't have any of the merging and collateral use of funds that your majors have, because there isn't that much money to do other things with.

I would just urge you to be sensitive to the problems of this particular industry.

I would mention to you that I—I agree with Congressman Dorgan. Price is more important than anything else. And there are a lot of uncertainties out there now.

I myself have been a lead player in changing the Natural Gas Policy Act in a way that some of my producers are not very happy with. But at the same time, tax considerations determine to a great extent whether you get investment capital. Independents need investment capital more than major companies need it.

Most of the production in America is done by independents, and in Kansas it is almost all done by independents, and small independents, people who produce far less than 10,000 barrels. So I would urge you to look closely at the situation, but remain sensitive to the fact that these tax provisions in existing law do help a unique part of the industry.

Chairman RANGEL. The tax definition of "independent" is rather broad.

Mr. GLICKMAN. You mean in terms of the size definition?

Well, we don't have many independents at the upper size of that scale, to be honest with you. And again, most of the independents that are producing in Kansas are not the upper size.

I don't want to get into the definition, because I don't have any specific background to get into it. But the fact of the matter is that we have several hundred independents in my hometown of Wichita alone, which is a lot, more than any other city in the country probably. And most of them are people who need the tax advantages that are available to them.

[The prepared statement follows:]

## STATEMENT OF HON. DAN GLICKMAN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF KANSAS

Mr. Chairman, thank you for the opportunity to appear today to make a brief statement concerning the tax treatment accorded independent oil and gas producers. It is a subject familiar to be because oil and gas exploraton and production is a leading industry in my home state of Kansas and most of the activity there is carried on by independents.

Unfortunately, the Kansas oil and gas industry is currently in a serious recession. The number of active rotary drilling rigs in Kansas, generally a reliable indicator of exploratory activity, has fallen from a record 224 in November, 1981 to 100 now. That means 55 percent of our large drilling machines are down and out of work. Production of natural gas also decreased by 30 percent during the past year, continuing a decline that began in 1973. Crude oil production has been declining since 1955 except for the past three years when there was a small increase; however, oil production resumed its decline this year when drilling decreased. In spite of this adversity, the independents continue to account for more than three-fourths of the crude oil production in Kansas, and across the United States, almost nine of every ten wells drilled is drilled by an independent. In view of this situation, now would not be the time to remove tax incentives for independent producers in Kansas.

Among the tax questions that you are interested in in these hearings is undoubtedly percentage depletion. As you know, independent producers may claim percentage depletion, but on a declining rate schedule. The percentage depletion rate has already decreased from 22 percent in 1980 to the current level of 16 percent, and will be phased down to 15 percent for 1984 and remain at that level in subsequent years. The amount of the percentage depletion deduction that may be taken is limited to 65 percent of the producer's taxable income for any year with certain adjustments. Moreover, depletion is subject to the minimum tax. The net percentage depletion available to independent oil and gas producers has thus reached a level equal to or below that granted producers of other natural resources.

While corporations may expense only 85 percent of their intangible drilling costs in the first year, individual oil and gas producers may elect to write off their entire cost. Those who do so, however, are subject under certain circumstances to the 20 percent alternatives minimum tax and the at-risk rules.

Independent producers also receive preferential windfall profit tax treatment, being eligible for reduced rates for certain amounts and categories of oil they produce and are exempt from tax on their qualified stripper production. Production attributable to royalty interests is likewise exempt to a certain extent, thereby protecting the thousands of farmers and landowners whose livelihood depends on their limited royalty income.

These special incentives provided independent oil and gas producers under the tax law are entirely justified considering the substantial risks they take with the relatively limited financial resources at their disposal. What is more, the incentives work: independent producers account for approximately 88 percent of all new well drilling in the United States, and better than 90 percent of the drilling in Kansas. In spite of the present world oil glut, we are not out of the woods energywise. We need to be farsighted and encourage exploration and development now so we don't again risk blackmail by OPEC. Tax incentives are particularly important to the industry in a mature producing state such as Kansas, where oil production dates back to 1855. After decades of vigorous production, the major oil companies have left Kansas for the most part, and independent producers now account for 76 percent of the crude oil production. The average oil well in Kansas now produces only about four barrels per day, and more than 90 percent of the oil wells are certified as stripper. Stripper wells in Kansas produce an average of only 2.67 barrels per day. With the depletion of large oil and gas reservoirs, the major companies have curtailed their exploration efforts in the state to seek larger, more lucrative prospects elsewhere. Only independent producers are left to seek and to find what amounts to an important contribution to our state and national energy supply.

In spite of this crucial role in bringing new reserves to the market, independents do not have the financial resources many of our large, integrated energy companies have. Independents rely heavily on their ability to attract funds from private, individual investors and thus the tax treatment of money invested with them and the money they put into new production in turn determines partially their ability to continue the exploratory activity. To the extent investors place their funds elsewhere, independents simply cannot afford to bring to market the marginal suppiies of energy which large companies too often neglect.

Clearly, Mr. Chairman, the industry's positive contribution would not be possible without the tax incentives now available to independent oil and gas producers. We in Kansas feel that they are necessary and appropriate to sustain the existence of a viable oil and gas industry in the state, given the economics of our production. A number of the tax incentives have been curtailed in recent years, and I want to urge you not to go further. These independent producers are taking the risks that will make or break our energy future. They have been dealt a blow by the recession that had a naturally negative impact on further production decisions. We should not exacerbate that by unwise actions here in Congress.

Beyond that, I would urge the Committee to look closely at regulatory changes being proposed by the Internal Revenue Service to severely curtail access to the tax incentives Congress specifically provided for stripper production. There has been strong criticism of the proposals, and I anticipate that they will be reworked. I recommend, instead, that they be scrapped altogether.

I appreciate the opportunity to present these views, and hope they will lead you to conclude that, with respect to independent oil and gas producers, the existing framework of taxes and incentives represents a good energy policy.

Chairman RANGEL. Mr. Anthony?

Mr. ANTHONY. Mr. Chairman, I have no questions. I just want to welcome our colleague to the Oversight Subcommittee. It has always been a pleasure to work with him in the past, not only on energy matters, but also on agricultural matters, where I served with him before I was appointed to the Ways and Means Committee.

Chairman RANGEL. Thank you, Congressman Glickman.

Congressman Shannon also has a statement which will be inserted at this point.

[The prepared statement follows:]

### STATEMENT OF HON. JAMES M. SHANNON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF MASSACHUSETTS

One of the principal questions being examined by the Subcommittee in these hearings—and quite rightly, in view of the inescapable need to enact further revenue raising measures this year—is whether the revenue that is lost through the provisions in the tax code that provide special treatment to certain types of oil and gas producers can be justified by a corresponding economic or energy policy gain. I would like to offer some reasons why I believe that this revenue loss cannot be justified and why I feel that percentage depletion, the expensing of intangible drilling and development costs, and the special Windfall Profits Tax treatment for independent producers and royalty owners should be terminated.

Currently all oil and gas producers are allowed to expense all or most of their intangible drilling and development costs—which include most of the expenditures made by an operator in preparation for drilling a well and the production of oil and gas from it—in the same year in which they are incurred, rather than treating them as capital expenditures and writing them off over the life of the well. Over the years we have seen some limits placed on the value of this deduction to the taxpayers who take it. IDC's claimed by individuals have been counted as preferences in the various forms of the minimum tax; most recently, in the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA), they were subjected to a 20-percent alternative minimum tax. Individuals and closely held corporations have been subjected to the at-risk rules. And TEFRA added a requirement that 15 percent of the IDC's of integrated corporations be written off over a thirty-six month period rather than expensed immediately. To me, all that indicates a feeling that the expensing of IDC's is simply too generous a deduction. I think that rather than tinkering with the expensing of IDC's in an attempt to make the results more like capitalization, and in the process creating complex rules that subject different types of taxpayers to varying treatment, we should straightforwardly end the expensing of IDC's.

Intangible drilling and development costs are not the day-to-day expenses of running an oil or gas well; they are the costs incurred in constructing this asset and preparing it for production. They account for 75 percent of the total costs of the well. In most other industries, costs like this are treated as capital expenditures. They are amortized over the life of the asset, or are added to the cost basis of the asset and depreciated accordingly. There is no reason why the assets of oil and gas producers should be treated differently.

The producers have always claimed that this sort of tax incentive is necessary to make the risks and expenses inherent in drilling for new oil and gas worthwhile. Immediate expensing, they say, is necessary to enable producers to cover the costs of dry holes and to give them an incentive for new exploration which may not pan out. A closer look at expensing, however, reveals some problems with this rationale.

In the first place, the IDC provisions were originally enacted at a time when domestic oil prices were controlled and gas prices were low, and it was at least arguable that the prices that oil and gas producers received for their products did not by themselves provide and adequate incentive for new exploration. With the decontrol of domestic oil prices and sharp increases in both oil and natural gas prices that we have experienced over the past few years (oil prices may be coming down, but they are still far higher than they were when this concept originated) this justification can no longer stand. The current high prices provide a perfectly adequate incentive for new exploration. When the decontrol of oil was discussed, we heard producers saying that we should let the free market work its will. Now that the decontrol of natural gas is being considered they're saying it again. If that is what they believe, then they should let the free market provide the incentive to produce.

Even if you accept the argument that the tax system should provide incentives for new exploration beyond those afforded by high prices, the expensing of IDC's is not a very efficient way to do it. This is because IDC expensing is equally available for wells drilled in proven fields and for wells drilled in more risky areas. Furthermore, current law already allows taxpayers who choose to capitalize their IDC's to expense the costs of a dry hole. There is thus no need for an additional tax break to cover these costs. If we want to retain some sort of tax incentive for new exploration, we could do it by eliminating IDC expensing and retaining the dry hole deduction.

Another tax subsidy that we should eliminate is percentage depletion. The percentage depletion allowance permits a taxpayer to account for the depletion of an asset by deducting each year a fixed percentage of his gross income from that property. In 1975 Congress wisely cut back on percentage depletion, reducing the percentage rate and limiting this allowance to certain types of natural gas and the first 1,000 barrels a day of production by independent producers and royalty owners. Other producers were required to use the cost depletion method, under which the taxpayer deducts his basis in the property over the life of the resource. Total deductions under this method cannot exceed the property's adjusted basis.

I believe that it is time we repealed the percentage depletion allowance altogether. As Congress recognized when it voted to restrict percentage depletion in 1975, percentage depletion is often more than a way of accounting for the depletion of an asset; often it is an outright tax subsidy. This is because percentage depletion often allows a greater deduction than the more straightforward cost depletion, and because over time the percentage depletion deductions can end up exceeding the property's adjusted basis. This means that the taxpayer may actually deduct more than the depreciation of his asset is costing him. The reason given for allowing independent producers to continue to use percentage depletion—that the tax system should continue to encourage high-risk exploration by these producers—reflects an awareness of this fact.

There is simply no reason to continue providing this subsidy to independent producers. In the first place, as has been discussed earlier, today's high oil and gas prices already provide a sufficient incentive for new exploration. Beyond that, however, I don't believe that independent producers are sufficiently distinguishable from other producers to continue giving them this subsidy. The independents have always claimed that they should receive this special treatment because it is they who do most of the risky, high cost exploration and because they rely on their oil and gas production as a source of income and new capital more heavily than integrated producers, who receive income from other activities. Independents do drill the greatest *number* of exploratory well, between 89 percent and 91 percent of them—hardly surprising when you consider that the Independent Petroleum Producers Association estimates that there are some 15,000 independent producers, while the estimates based on IRS data show that between half a million and a million persons claim tax treatment as independent producers.

In terms of actual expenditures and production, however, the integrated companies are way ahead—they spend much more on exploration and development of wells, and they find more oil and gas when they do drill, than do the independents. Figures from the Census Bureau show that in 1980 the top 50 oil producing companies, most of which are integrated companies, were responsible for 76 percent of all expenditures for exploration and 68 percent of expenditures for drilling and equipping exploratory wells. A study by the Petroleum Industry Research Foundation of 26 integrated oil companies[1] showed that these producers contributed 43 percent of the U.S. oil and gas reserve additions due to exploratory drilling from 1979–1980. They spent four times more than the U.S. average per exploration well; drilled wells 36 percent deeper than the U.S. average; and found oil or gas in 83 percent of all their wells and 49 percent of their exploratory wells, compared to 69 percent and 46 percent for the rest of the industry. They increased their expenditures for exploration and development by 54 percent from 1979 to 1980, compared with 23 percent for the industry as a whole. Furthermore, contrary to independents' claim that they do more risky drilling, it is the large integrated companies that have been exploring such high-cost, high-risk areas as Alaska and the offshore sites and the most promising new areas, the Western Overthrust Belt. The independents, on the other hand tend to do their drilling in the traditional producing areas. This differential treatment is thus an inefficient and ineffective means of subsidizing new and risky exploration.

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[1] It should be noted that one of those companies, Louisiana Land and Exploration does qualify as an independent producer for tax purposes, although it is very large and does have some refining operations.

Nor is it true that independent producers are always small, struggling companies with few sources of income or capital. Some independents are larger than some integrated companies; some of them do carry on refining or retail activities while staying below the maximum allowed for independent producer status. Often independent producers are wealthy individuals who have acquired a limited partnership in a production company as a lucrative tax shelter.

The problems faced by those independent producers that are small and struggling are due not so much to their independence as to their smallness. They are the problems faced by small businesses in every field and should be dealt with as a matter of overall small business policy, not by special exceptions for one segment of one industry. The current differences in treatment between independent and integrated producers only invite abusive manipulation of the producer's structure and activities in order to qualify for the special tax advantages.

Percentage depletion for royalty owners should also be eliminated. For one thing, it is senseless to give a tax subsidy ostensibly intended to encourage exploration to taxpayers who have only a non-working interest and and whose only role in the exploration and development process is to collect one-eight of the resulting income. When threatened with the loss of this deduction, the royalty owners claim that most of them are elderly and low-income people who should not be deprived of this tax break. An analysis of 1981 tax returns, however, shows that 65 percent of the royalty income listed on those returns was paid to people with adjusted gross incomes of over $50,000. Those whose income is truly low will have little or no tax liability in any case. Furthermore, figures for 1980 tax returns show that only 38 percent of returns listing royalty income also claimed the exemption for those over 65; this represented 28.6 percent of the royalty income listed on all returns.

For the same reasons, no useful purpose is served by giving royalty owners a two-barrel-a-day exemption from the Windfall Profits Tax, or by giving independent producers lower Windfall Profits Tax rates. Nor can the exemption for stripper well production by independents withstand close scrutiny. The purpose for this exemption was apparently to encourage producers to wring every last drop of oil out of the ground by providing them with an incentive to keep stripper wells (those producing less than ten barrels a day) in production. Again, this is an inefficient subsidy, and one that contributes little to meeting energy needs. An Energy Department survey shows that stripper wells contributed only 13.1 percent of total oil production in 1980, and 40 percent of this amount was produced by the 24 largest oil companies. There is therefore little justification for giving this exemption only to independent producers. Furthermore, many people feel that there is already sufficient incentive for producers to go after this oil, as it is found in already proven fields and thus represents a relatively low risk. And finally, all three of these Windfall Profits Tax exemptions make an already complex tax that much more difficult to administer.

Besides the specific problems with the IDC, percentage depletion, and Windfall Profits Tax provisions that I have already discussed, I feel in general terms that allowing these provisions to remain in the tax code poses some overall problems in terms of both tax policy and energy policy. The provisions represent an important means of tax avoidance for an industry that already enjoys too many tax loopholes. Some studies have been made recently of various corporations' "effective tax rates"; that is, the percentage of their income that is actually taxed once the various exemptions, deductions, and credits that they can utilize are subtracted from the statutory 46 percent rate. Different analysts use different methodologies to arrive at their figures, but they have all found the oil industry to be paying a low effective rate. The Joint Committee on Taxation, for instance, found that the effective tax rate on U.S. income from crude oil production was only 3.1 percent in 1981—far less than most other industries paid on their domestic income. An analysis by Jane Gravelle of the Congressional Research Service found the effective tax rate on new investments in oil extraction, taking into account the tax law changes in 1982 and assuming a 6 percent inflation rate, to be 12 percent. She also broke down effective tax rates for different types of producers according to the deductions they could take and the applicability of the minimum tax and found that while the effective rate was never above 31 percent on this type of income, in some cases—when the taxpayer was an independent producer not subject to the minimum tax and taking percentage depletion—there was actually a negative rate. This means, in effect, that the current tax provisions are shifting income from the ordinary taxpayers to the investors in these producing companies.

We are in a period when we simply cannot afford any tax expenditures that are not justified by some legitimate policy goal. Retaining the provisions that allow expensing of IDC's, percentage depletion for independent producers and some natural gas, and special Windfall Profits Tax treatment for independents and royalty owners will cost us $4.4 billion next year and $32.2 billion between 1984 and 1988. I have seen no figures showing how much, if any, increased production we are getting for this tax expenditure; no figures that show how many barrels of oil we get for each dollar of lost revenue. If the producers think that we should retain these provisions, I would like to see them come up with some figures that would justify them in terms of energy policy.

To sum up, the answer to the question posed at the beginning of this statement—whether the revenue that is lost through the IDC, percentage depletion, and Windfall Profits Tax exemption provisions in the tax code can be justified by a corresponding economic or energy policy gain—is an emphatic "no." After the Subcommittee has reviewed the testimony presented at these hearings, I hope that it will recommend to the Ways and Means Committee that we raise some revenue this year by eliminating these provisions.

Chairman **Rangel**. We have a panel of Jane G. Gravelle, Specialist in Industry Analysis and Finance, Economics Division, Congressional Research Service, Library of Congress; Professor Robert Conrad, Department of Economics, Duke University; Professor Arthur Wright, chairman of the Department of Economics, University of Connecticut; and Professor Walter Mead, Department of Economics, University of California, Santa Barbara.

On behalf of the committee, we welcome you.

## STATEMENT OF JANE G. GRAVELLE, SPECIALIST IN INDUSTRY ANALYSIS AND FINANCE, ECONOMICS DIVISION, CONGRESSIONAL RESEARCH SERVICE, LIBRARY OF CONGRESS

Ms. **Gravelle**. Mr. Chairman, I am Jane Gravelle, Specialist in Industry Analysis and Finance, Economics Division, Congressional Research Service of the Library of Congress.

I would like to thank you for the invitation to appear before you today to present my study on effective Federal tax rates on income from oil and gas extractions which I would like to submit for the record.

[The prepared study follows:]

# EFFECTIVE TAX RATES ON OIL AND GAS INVESTMENT

(Prepared by Jane G. Gravelle, Specialist in Industry Analysis and Finance, Economics Division, Congressional Research Service, Library of Congress)

## I. INTRODUCTION

Tax rules applying to investment in extraction of oil and gas are differentiated among different types of taxpayers. Varying rules apply depending on the legal status of the producer (corporate, individual, limited partnership) and the economic activities of the producer (integrated or independent).

This study measures the tax rates which apply under the different tax rules including regular and minimum tax rules. The results indicate that tax rates on oil extraction are low compared to overall effective tax rates on capital income and these rates are actually negative in cases where percentage depletion is available. While the economic effects of making the rules consistent with those applied to corporate integrated producers are uncertain, they are likely to be quite small.

## II. A DESCRIPTION OF TAX TREATMENT

Under present law, income from new investment in oil and gas reserves is subject to both an income tax and a windfall profits tax. The income tax provisions are differentiated by producer depending on whether or not the producer is an integrated corporation, an integrated non-corporate producer, an independent corporate producer, an independent individual producer or an independent individual producer who is a limited partner.

### Income Tax Rules

Investment in oil and gas extraction includes investments in tangible depreciable assets (e.g., drilling rigs), and various depletable investments such as land acquisition, geological and geophysical expenses and intangible drilling costs. Oil and gas producers also use some structures in their business. All of these costs are recovered under different rules in the tax law.

Investment in depreciable equipment assets is recovered under ACRS depreciation rules which allow recovery over five years and a 10 percent investment credit. Under new tax rules adopted in 1982, the basis of these assets is reduced by one half of the investment credit. Investment in structures is recovered over 15 years and receives no investment credit. The tax treatment of these assets is identical for all taxpayers.

Investment in the acquisition of oil and gas reserves is recovered through depletion or through expensing as a general rule. Rules vary by taxpayer, however. All taxpayers are allowed to expense properties or wells which are abandoned. Intangible drilling costs on successful properties are expensed. Integrated corporate producers are required, however, to amortize 15 percent of their intangible drilling costs over a three year period. A portion of the cost on successful properties is recovered through depletion. Percentage depletion was eliminated in 1975 and these costs must be capitalized and recovered over the life of the property. Independent producers are, however, allowed to take percentage depletion (deduct 15 percent of the income from the property) on the first 1,000 barrels per day of production per taxpayer.

Both corporations and individuals are subject to a minimum tax. In the case of corporations, a minimum tax of 15 percent of certain preference items in excess of $10,000 or regular tax liability (whichever is greater) is added to the regular tax. Percentage depletion in excess of the cost basis is included in the corporate minimum tax base. Individuals are subject to an alternative minimum tax of 20 percent which is paid if it exceeds the regular tax. Included in the base are excess percentage depletion and intangible drilling costs in excess of the costs if these were capitalized. Individuals can avoid the minimum tax on intangible drilling costs by electing to recover these costs through depreciation. In the case of a limited partner, the minimum tax can be avoided only if the intangible drilling costs are recovered over a ten year period.

Windfall Profits Tax

Investment in oil and gas reserves is subject to a windfall profits tax on the difference between the selling price and a base price which rises with the inflation rate plus 2 percent per annum. Eventually, this windfall profits tax will disappear if the relative price of oil does not rise at 2 percent per year. The windfall profits tax is deducted for purposes of computing income tax.

## III. THE MARGINAL TAX RATE ON NEW INVESTMENT

The tax treatment of new oil and gas investment is highly differentiated and these different rules can lead to differences in effective tax rates on new investments. Table 1 provides estimates of the effective tax rates on new investments under a variety of different circumstances including the legal status of the producer, and whether or not the producer is eligible for percentage depletion. The table also illustrates two tax rates because the flat rate minimum tax can have a different impact depending on the individual tax rate.

The minimum tax calculations in these examples are set up to yield the maximum effects of the minimum tax. For example, they imply that for individuals the minimum alternative tax on items included in the base is larger than the individual's regular tax and that the individual at the margin experiences both regular and minimum tax effects on investment. Very few individuals would be likely to be in these circumstances.

The table also reports the combined tax rates of the windfall profits tax and the income tax. These tax effects, already small, will gradually disappear over time unless the relative price of oil rises steadily. The formulas underlying these calculations assume that oil prices will keep pace with inflation.

The tax rates in this table indicate that tax rates on oil and gas production are relatively low and remain low even when the windfall profits tax is added in. Studies of overall tax rates on depreciable assets indicate the average tax rate is about 25 percent, 1/ a rate well above any of the tax rates in the table except for certain cases when the minimum tax applies. Note also that with percentage depletion and no minimum tax, tax rates are negative. That is, the

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1/ See "Effective Tax Rates and Tax Changes in the 97th Congress" by Jane G. Gravelle, Congressional Research Service, January 3, 1983.

Table 1. Effective Tax Rates on Oil and Gas Extraction

| | Income tax alone | Income tax plus windfall profits tax |
|---|---|---|
| NO MINIMUM TAX APPLICABLE | | |
| No Percentage Depletion | | |
| Integrated corporation (46% tax rate) | 14 | 16 |
| Independent, 46% tax rate | 13 | 15 |
| 25% tax rate | 4 | 6 |
| Percentage Depletion | | |
| Independent, 46% tax rate | -8 | -6 |
| 25% tax rate | -5 | -2 |
| MINIMUM TAX APPLICABLE | | |
| Corporate, with Percentage Depletion (46% tax rate) | 1 | 3 |
| Non-corporate | | |
| With Minimum Tax on Intangible Drilling Costs | | |
| No percentage depletion, 46% tax rate | 30 | 31 |
| 25% tax rate | 20 | 21 |
| Percentage depletion 46% tax rate | 23 | 24 |
| 25% tax rate | 19 | 21 |
| ACRS Recovery for Intangible Drilling Costs | | |
| No percentage depletion, 46% tax rate | 15 | 16 |
| 25% tax rate | 1 | 3 |
| Percentage depletion 46% tax rate | 5 | 7 |
| 25% tax rate | 2 | 3 |
| Ten Year Amortization of Intangible Drilling Costs (Limited Partner) | | |
| No percentage depletion, 46% tax rate | 29 | 30 |
| 25% tax rate | 13 | 14 |
| Percentage depletion 46% tax rate | 22 | 23 |
| 25% tax rate | 13 | 14 |

Source: See Appendix for method of calculation and assumptions used.

tax treatment is better than having no tax at all. This negative tax rate is larger the higher the individual tax rate applicable.

The effects of the minimum tax can largely be avoided, by most taxpayers (other than limited partners) by electing ACRS treatment on intangible drilling costs. This occurs because the present value of the ACRS deductions plus the investment credit are only slightly less generous than expensing. Indeed at lower tax rates, these values are greater than expensing and these individuals should prefer recovery through depreciation and investment credits where the minimum tax is not a consideration.

The circumstance where the minimum tax becomes very important is in the case of a limited partner where the higher tax rates with ten year amortization are roughly equivalent to paying the minimum tax. For lower tax rate individuals, the ten year amortization can lower the tax rate and would be preferred to paying the minimum rate.

The minimum tax appears, in these circumstances, to eliminate the instances of negative tax rates when percentage depletion is used, although tax rates remain relatively low.

## IV. POTENTIAL ECONOMIC EFFECTS OF THE TAX RULES

It is possible to convert these tax rates into equivalent changes in oil and gas prices (i.e., determine how much prices might have to change to induce the same benefits or penalties as higher or lower taxes). For example, the difference between the treatment for an integrated corporate producer and an independent at the same tax rate eligible for percentage depletion is roughly equivalent to a 10 percent increase in price. If the elasticity of demand for investment is equal to one as some evidence suggests, these producers eligible for percentage depletion might have expanded investment by 10 percent.

The aggregate effects on overall oil industry investment would be likely to be relatively small. Much of output is produced by integrated corporations. Furthermore, only those individuals who experience percentage depletion on marginal investments would be affected by the price change at the margin. If, for example, 10 percent of production is affected (which is likely to be an overstatement in any case), investment might only expand by 1 percent. Unfortunately, there are no data available which can be used to estimate this effect with precision. Such a price change is, however, dwarfed by the change in relative prices which have occurred in recent years.

A similar point can be made with respect to the minimum tax. The effects of the minimum tax in the absence of percentage depletion when depreciation recovery is used is neglible (only 1/2 of one percent) as is the advantage of full deduction of intangible drilling costs (i.e., not requiring a portion of the intangible drilling costs to be recovered over three years as in the case of the integrated producer). When percentage depletion is allowed and the minimum tax applies, the result is the equivalent of 7 percent increase in price for the corporation and a 5 percent price increase for the individual using depreciation deductions to avoid the minimum tax.

The price effects for the minimum tax for limited partners required to amortize over 10 years is somewhat larger--an equivalent 10 percent price reduction when there is no percentage depletion and an equivalent 5 percent price reduction when percentage depletion is available.

As indicated earlier, these cases where the minimum and regular taxes would apply in full would be limited and are likely to have little effect on investment.

## APPENDIX

With investments where output declines at a geometric rate, the effective tax rate can be measured as (r-R)/r) where R is the after tax real discount rate and r is the pre-tax return measured as:

$$r = \frac{(R+d)\ (1 - uz - k)}{(1 - u^*)} - d$$

where d is the economic depreciation rate, z is the present value of depreciation deductions per dollar of investment, u is the taxpayer's statutory marginal tax rate, k is the investment credit rate and u* is the tax rate on gross receipts, equal to u in the absence of percentage depletion. When percentage depletion is allowed (at a 15 percent rate), the tax rate on receipts u* is equal to .85u. When percentage depletion is allowed and the minimum tax is also applied to percentage depletion, the tax rate u* is equal to .85u + .15m where m is the rate of the minimum tax. (This treatment actually overstates the effect of the minimum tax somewhat since the minimum tax only applies to percentage depletion in excess of cost.) The minimum tax is equal to 15 percent for corporations and 20 percent for individuals. The tax rate is therefore equal to .85u + .0225 for corporations and .85u + .03 for individuals when the minimum tax applies.

The value of z depends on how costs are recovered. Depreciable assets are recovered through depreciation (over five years) at 150 percent declining balance rates and with only 95 percent of the cost depreciated. An investment credit of 10 percent is also allowed. Intangible drilling costs and abandonment losses are expensed so that z is equal to 1 for that portion of cost.

For corporations, 15 percent of intangible drilling costs are recovered over three years at a straight line rate. Structures are recovered over 15 years at a 175 percent declining balance rate. Amounts recovered through cost depletion are recovered at a declining balance rate with the rate assumed to be equal to the actual economic depletion in the result.

An individual facing a minimum tax on intangible drilling costs has the option of recovering that cost under the depreciation system or, in the case of a limited partner, over a ten year period at a straight line rate in order to avoid the minimum tax. If the minimum tax is actually paid, the rate of tax in the denominator (u) is equal to u-m, where m is the minimum tax, equal to 20 percent for individuals.

The windfall profits tax may be included in the calculations, to measure the combined rate of the windfall profits tax and the income tax. Since the windfall profits tax is applied to the difference between the sales price and a moving base which rises at the inflation rate plus 2 percentage points per year, the original formula will be altered to:

$$r = \frac{((R+d)\ (R+d-.02))\ (1-uz-k)}{((R+d)\ (1-w\ (1-x))-.02(1-w))\ (1-u)} - d$$

where w is the rate of the windfall profits tax and x is the ratio of the starting base price to the sales price. This formula assumes that oil prices will rise at the inflation rate.

In calculating the effective tax rates, the following assumptions are made. First, a typical oil extraction investment is assumed to require 9 percent of its capital stock in depreciable equipment, 85 percent in acquisition of oil reserves including intangible drilling costs and 6 percent in structures. Of the 85 percent in acquisition of reserves, 39 percent is recovered through intangible drilling costs, 52 percent through abandonment losses and 9 percent through either cost or percentage depletion. These ratios are based on data used to set regulated natural gas prices and data on the use of capital assets by industry from the national income and product accounts.

The depreciation rate used is the weighted average of reserves, structures and depreciable equipment, set respectively at .0663, .033 and .1650. These are estimates derived by Charles Hulten and Frank Wykoff in their studies of economic depreciation ("The Measurement of Economic Depreciation," In Depreciation, Inflation and the Taxation of Income From Capital, The Urban Institute, 1981). 2/

The value of x is set at .8, reflecting a current estimated base price of $23 as compared to a selling price of $29. The windfall profits tax rate used (w) is the 15 percent rate scheduled for 1986 although the rate will be slightly higher in the interim. Over time the effect of the windfall profits tax will disappear.

The discount rate used is 6 percent, at the upper range of discount rates commonly used in this type of analysis to reflect the relatively risky nature of oil production. The actual discount rate used has relatively little effect on effective tax rates. The inflation rate is assumed to be 6 percent.

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2/ Technically speaking, it is better to weigh pre-tax returns rather than weigh depreciation rates and tax depreciation values. In this case, there is little difference and it makes the calculation of the windfall profits tax effectc much less complex.

Ms. **Gravelle**. I have been asked to indicate at the outset of my statement that the congressional guidelines on objectivity and nonpartisanship require that the CRS staff confine their testimony to technical professional and nonadvocative aspects of the matters under consideration and limit themselves to questions within their fields of expertise.

Under present law, income from new investment in oil and gas reserves is subject to both an income tax and a windfall profit tax.

The income tax provisions are differentiated by producer depending on whether or not the producer is an integrated corporation, an integrated noncorporate producer, an independent corporate producer, an independent individual producer, or an independent individual producer who is a limited partner.

Investment in oil and gas extraction includes investments in tangible depreciable assets, for example, drilling rigs, and various depletable investments such as land acquisition, geological and geophysical expenses and intangible drilling costs.

Oil and gas producers also use some structures in their business. All of these costs are recovered under different rules in the tax law.

Investment in depreciable equipment assets is recovered under ACRS depreciation rules which allow recovery over 5 years and a 10-percent investment credit. Under new tax rules adopted in 1982, the basis of these assets is reduced by one half of the investment credit. Investment in structures is recovered over 15 years and receives no investment credit. The tax treatment of these assets is identical for all taxpayers.

Investment in the acquisition of oil and gas reserves is recovered through depletion or through expensing as a general rule. Rules vary by taxpayer, however. All taxpayers are allowed to expense properties or wells which are abandoned. Intangible drilling costs on successful properties are expensed.

Integrated corporate producers are required, however, to amortize 15 percent of their tangible drilling costs over a 3-year period.

A portion of the cost on successssful properties is recovered through depletion. Percentage depletion was eliminated in 1975 and these costs must be capitalized and recovered over the life of the property.

Independent producers are, however, allowed to take percentage depletion—deduct 15 percent of the income from the property—on the first 1,000 barrels per day of production per taxpayer.

Both corporations and individuals are subject to a minimum tax. In the case of corporations, a minimum tax of 15 percent of certain preference items in excess of $10,000 or regular tax liability, whichever is greater, is added to the regular tax. Percentage depletion in excess of the cost basis is included in the corporate minimum tax base.

Individuals are subject to an alternative minimum tax of 20 percent which is paid if it exceeds the regular tax. Included in the base are excess percentage depletion and intangible drilling costs in excess of the costs if these were capitalized.

Individuals can avoid the minimum tax on intangible drilling costs by electing to recover these costs through depreciation.

In the case of a limited partner, the minimum tax can be avoided only if the intangible drilling costs are recovered over a 10-year period.

Investment in oil and gas reserves is subject to a windfall profit tax on the difference between the selling price and a base price which rises with the inflation rate plus 2 percent per annum.

Eventually, this windfall profit tax will disappear if the relative price of oil does not rise at 2 percent a year. The windfall profit tax is deducted for purposes of computing income tax.

An increasingly popular method used to measure the effects of different tax provisions in a single number is the measure of effective tax rate on new investment.

This approach uses a discounted cash flow method to determine the return on a typical investment with and without tax payments and credits.

The difference between the pretax return and the aftertax return is then used to measure an effective tax rate on new investment. For example, if the pretax return is 10 percent and the aftertax return is 5 percent, then the effective tax rate is 50 percent.

Using this approach, estimates of the effective tax rates were prepared for new oil and gas extraction investments under a variety of different circumstances including the legal status of the producer, and whether or not the producer is eligible for percentage depletion.

Combined tax rates of the windfall profit tax and the income tax are also reported. These tax effects, already small, will gradually disappear over time unless the relative price of oil rises steadily. The formulas underlying these calculations assume that oil prices will keep pace with inflation.

The results indicate that tax rates on oil and gas production are relatively low and remain low even when the windfall profit tax is added in. The rate for integrated corporate producers is 14 percent for the income tax alone and 16 percent for the combined income and windfall profit tax.

For other producers not subject to percentage depletion, there rates are 13 and 15 percent; respectively. Studies of overall tax rates on depreciable investment indicate the average tax rate is about 25 percent.

With percentage depletion tax rates on income from oil and gas extraction are negative—minus 8 percent for the income tax alone and minus 6 percent for the combined windfall profits tax and income tax. That is, the tax treatment is better than having no tax at all. Application of minimum taxes can raise these rates.

The effects of the minimum tax can largely be avoided, however, by most taxpayers—other than limited partners—by electing accelerated cost recovery treatment on intangible drilling costs.

This occurs because the present value of the ACRS deductions plus the investment credit are only slightly less generous than expensing.

Indeed, at lower statutory tax rates, these values are greater than expensing and these individuals should prefer recovery through depreciation and investment credits even where the minimum tax is not a consideration.

The circumstance in which the minimum tax becomes very important is in the case of a limited partner where the higher tax rates with 10-year amortization are roughly equivalent to paying the minimum tax.

It is possible to convert these tax rates into equivalent changes in oil and gas prices; that is, determine how much prices might have to change to induce the same benefits or penalties as higher or lower taxes.

For example, the difference between the treatment for an integrated corporate producer and an independent at the same statutory tax rate eligible for percentage depletion is roughly equivalent to a 10-percent increase in price.

If the elasticity of demand for investment is equal to one as some evidence suggests, these producers eligible for percentage depletion might have expanded investment by 10 percent.

The aggregate effects on overall oil industry investment would be likely to be relatively small. Much of output is produced by integrated corporations.

Furthermore, only those individuals who experience percentage depletion on marginal investments would be affected by the price change at the margin.

If, for example, 10 percent of production is affected—which is likely to be an overstatement in any case—investment might only expand by 1 percent.

Unfortunately, there are no data available which can be used to estimate this effect with precision. Such a price change is, however, dwarfed by the change in relative prices which occurred in recent years.

Chairman RANGEL. Thank you very much.

Could we hear now from Prof. Robert Conrad, Duke University?

## STATEMENT OF ROBERT F. CONRAD, ASSISTANT PROFESSOR OF ECONOMICS, DUKE UNIVERSITY, AND RESEARCH ASSOCIATE, HARVARD INSTITUTE FOR INTERNATIONAL DEVELOPMENT, HARVARD UNIVERSITY

Mr. CONRAD. I am Robert F. Conrad. I am currently an assistant professor of economics, Duke University, and a research associate at the Harvard Institute for International Development, Harvard University.

I have a prepared statement which I would like to summarize.

Chairman RANGEL. Without objection, your full statement will be entered in the record.

Mr. CONRAD. In my prepared statement I see two issues with respect to the current tax treatment of oil and gas.

First, there is the differential tax treatment within the industry; second, is the differential tax treatment of the industry as a whole which might reallocate resources between industries within the entire economy.

With respect to intraindustry allocation, from an economic point of view, every well will have a marginal barrel, every field will have a marginal well and every tract of land will be a marginal prospect beyond which it will not be profitable to extract, develop, or explore.

In the absence of differential taxation the economic value of that marginal barrel, marginal field, or marginal prospect will be the same across all fields and independent of the pattern of ownership.

This does not imply that every individual will value that same barrel in exactly the same way. People would have different preferences toward risk, different levels of wealth, et cetera, which may cause a differentiation in the personal evaluation but the valuation from the standpoint of the economy as a whole will value it equally.

On page 3 of my prepared testimony, I state seven different possible incentives created by the current differential tax treatment within the oil and gas industry.

I do not mean to imply while listing these seven that the integrated oil companies will be going away or the economy will somehow suffer irreparable harm.

Rather, market forces will assure that the tax effects are dispersed throughout the economy.

Another way of saying this is that after the market works the tax incentives that the independent producers or the ones given preferential treatment at the margin will be no better off than they were before because the net of tax returns will be equalized in the economy. Some will be richer but they will still only be making a competitive return.

In order to illustrate the possible incentives I performed a study similar to one done by Professor Harberger who submitted testimony to the committee some 30 years ago.

The results of this are shown on table 4 in my statement.

The question that was asked in preparation of these estimates is the following: How much more would an independent producer be willing to pay for a tract of land over and above that paid, the amount paid by an integrated producer because of the tax incentives? That is to say, how much are the differentials worth?

If you look at the table—I ran this basically looking at two things. One is the ratio of price to cost; that is, how much profitability at the margin would this tract have?

Chairman RANGEL. Which table are you referring to, sir? Table 4?

Mr. CONRAD. Table 3. Excuse me.

By looking at the ratio of average cost to price you get some feel of how much these incentives are created at the margin in terms of profitability of the field, and, second, looking at different field prices because of the effects on the windfall profit tax.

The way to interpret these numbers is that if the number were equal to one there would be no difference between the majors'—integrated firms'—willingness to pay and the independents' willingness to pay.

A number greater than one indicates that because of tax incentives an independent producer will be willing to pay more than an integrated firm.

As shown clearly, all the numbers are greater than one. That comes as no surprise since clearly the intent of the law was to favor independnts over integrated firms.

What is interesting, however, is that the numbers rise both as a function of the price of crude oil, the field price, but also as the profit margin falls.

Now, that means in looking at it in terms of an independent producer that a small field—given limited capital resources—a small field for an independent producer is worth even more than a large field for an independent producer because of the tax incentives.

The implication of this is that the tax incentives may lead to segmentation of the industry or an even larger segmentation merely because of tax incentives.

The efficiency cost of any difference must be weighed against the potential benefits. I can think of two that have been raised today. One is to promote competition; the second is the access to capital markets.

As an economist, it is hard to justify using tax incentives to increase competition because it is my view that a tax system with tax incentives is by its very nature anticompetitive. Only those with a tax liability are able to take advantage of the incentives at the expense of those with no tax liability at all.

Second, is the issue of access to the capital markets.

Once again, it comes back to the issue of if producers, integrated or not, have enough income to pay taxes they have attracted the sufficient capital to pay the taxes in the first instance.

Second, if producers were truly having difficulties in raising capital, then maybe the market is simply telling them something. That is to say, investors prefer to take their savings and invest in some other assets rather than investing in this activity.

Having said this, the issue becomes what should be done; or looking at alternatives, what should be done? There is more than one way to solve the problem of differential taxation within the industry; one is to eliminate incentives for the independents, the other is give the incentives to the majors.

In looking at this, I performed the same analysis looking at three different types of investments on a building; (1) 50 percent building; 50 percent ACRS investment; and (3) 100 percent ACRS property. This is table 4.

The columns represent alternatives, one is to treat the entire industry like the integrated firms; the other one is to treat the entire industry like currently the independents are treated; and three is to treat the entire industry the way the independents are currently treated and eliminate the windfall profit tax.

Now, a ratio of greater than one implies that an oil and gas investment in general will be more attractive to investors than either of the three alternatives outlined.

As you can see, under all three alternatives, with the exception of one, the 100-percent ACRS property, whichever way the—which way the elimination of the differential of the tax incentives goes, a tax on oil and gas in general would be more profitable with the exception of the 100-percent ACRS property tax case where all producers are treated as the integrated firms.

I would like to close with the following thought. One, intangible drilling costs are capital expenditures from an economic perspective, and, from an economic perspective, should be treated like any other asset.

That is not, however, implying that intangible drilling costs should be amortized. If the purpose of the income tax is to move toward a cashflow tax, then I think the tax treatment of them is proper.

With respect to percentage depletion there are well-known economic incentives created by percentage depletion which are in my testimony, and I would just like to briefly outline some possible options.

One is to treat it like ACRS property. Two, is to allow immediate expensing. Three, move to cost depletion similar to financial accounting. Given the current incentives in the tax law with respect to other industries it may in fact be a penalty with respect to this one particular aspect—with respect to the one particular aspect of the taxation of oil and gas—to require the cost depletion over the life of the property.

The reason is that with respect to ACRS property it is certainly clear that in most cases the asset lives of most property treated under the tax laws are longer than the ACRS guidelines.

So with respect to this one thing, it—cost depletion throughout the entire life of the asset—may in fact provide a marginal penalty to the oil and gas industry.

Third, the windfall profit tax acts in the opposite direction of the tax incentives. In fact, it discourages production at the margin and so the two together—the tax incentives and the windfall profit tax can cancel each other out to some extent, but not completely.

Finally, there is the issue of the reason for the tax incentives in the oil industry in the first place, largely energy security, reduced dependence.

As an economist, these agreements imply that the market price of crude oil is too low relative to its social value, not that the price of capital is too high in the industry.

Now, capital and crude oil are closely related given the capital intensity of the industry but they are not the same thing. It is probably better to introduce policies to increase the field price of crude oil rather than to change the cost of capital to the industry.

Thank you very much.

[The prepared statement follows:]

## STATEMENT OF ROBERT F. CONRAD

My name is Robert F. Conrad. I am currently an Assistant Professor of Economics, Duke University and a Research Associate at the Harvard Institute for International Development, Harvard University. My fields of specialization within Economics include the taxation of capital and the taxation of natural resource industries.

I appear today as a witness on the basis of an invitation from the Committee on Oversight of the House Ways and Means Committee. I therefore represent no vested interest in the issues which are to be addressed in these hearings and my remarks should be taken solely as my opinions.

### 1. Introduction

From an economic point of view at least two issues are raised from the current income tax treatment of oil and gas investments. First, parties with an economic interest in oil and gas production may be taxed differently under current law. Three of the more important differences in the tax treatment of oil and gas producers are: 1) integrated oil producers must capitalize 15% of their Intangible Drilling and Development Costs (IDCs) and amortize this amount over a 36 month period, while non-integrated oil producers may expense 100% of these costs;[1] 2) integrated oil producers are not allowed the benefits of percentage depletion while this privilege is available, in a limited form, to both non-integrated producers and royalty holders; 3) under the provisions of the Windfall Profits Tax integrated producers are taxed at higher rates than non-integrated producers on Tier 1 Oil, and some types of oil produced by non-integrated firms (e.g. stripper oil) is exempt from this tax. These differences in tax treatment raise the issue of intra-industry efficiency in the allocation of resouces within the oil and gas sector.

The second issue concerns tax incentives. This is particularly true with regard to the provisions of the tax law which allow expensing of IDCs, either all or in part, and which provide for percentage depletion for a portion of the production of a segment of this industry. The taxation of oil and gas exploration and production as a whole creates incentives which might reallocate capital from other sectors of the economy into the oil and gas sector.

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[1] Individuals and/or corpor ations however may be subject to a minimum tax on these expenses under the minimum tax on preferences rules. For a complete description of these differences see: Description of the Statutory Provisions Affecting the Tax Treatment of Domestic Oil and Gas Producers prepared for these hearings by the Staff of the Joint Committee on Taxation.

Thus, differentials in the tax treatment of this industry raise the issue of inter-industry efficiency with respect to the allocation of resources in the economy as a whole.

In this testimony I would like to describe what I believe to be the nature of the economic incentives created by the current tax treatment of oil and gas production. In addition, I will provide some estimates of the relative magnitude of these incentives; both with respect to the intra-industry and inter-industry allocation of resources. These estimates are based on the methodology developed by Arnold C. Harberger (1955, 1961). Much has changed since Professor Harberger presented his initial study to the Joint Committee in 1955; however his basic methodology is as sound today as it was 28 years ago. Therefore, my presentation will serve not only to provide an appraisal of the current situation, but it will provide a comparison with the past Congressional record.

## 2. Intra-Industry Efficiency

### 2.1 The Efficiency Cost Associated with Differential Tax Treatment

In the absence of differentials in taxation within an industry, competitors in that industry will invest until the point where the net of tax return from increased investment is equal across all firms in the industry. In addition, the gross of tax returns from these investments at the margin will be equal within the industry. The equality of the tax wedge created between the gross-of-tax and net-of-tax return across firms is the standard condition for economic tax neutrality within an industry. In the context of the oil and gas industry, this result implies that every well (no matter how low or high cost) will have a marginal barrel; every field will have a marginal well and every area will have a marginal prospect beyond which it will not be economical to produce, to develop or to explore. Furthermore, independent of the pattern of ownership (or of economic interest) the risk adjusted net-of-tax rates of return will be equal for all producers.

Such neutrality does not exist in the oil and gas industry.[2] Therefore in a competitive market, the differentials in tax treatment will create a situation where the difference between the gross-of-tax and net-of-tax returns will differ according to the composition of the economic interest in oil and gas investments. Once the differential tax treatment has been subjected to the discipline of the market, the net-of-tax returns will once again be equal at the margin, but the gross-of-tax returns will differ: e.g. the gross-of-tax return will be higher for a shareholder of an integrated oil company than the return for a shareholder of a non-integrated firm; however, the net-of-tax returns will be equal. Such non-neutral tax treatment might create the following incentives among others:

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[2] I do not believe anyone can dispute that fact. The law is quite clear about exemptions and lower rates for the Windfall Profits Tax. In addition the disallowance of percentage depletion and the requirement that 15% of IDC's be capitalized are clearly intended for the integrated companies.

1. A non-integrated firm may produce more from a given oil well (or field) than an integrated producer. That is, the point where marginal net of tax cost is equal to the net-of-tax price might occur at a higher level of output for a non-integrated producer than for an integrated producer.

2. A non-integrated producer may have a different time profile of production than an integrated producer for the same property. That is, a non-integrated producer might produce more oil earlier and less later in the life of a well than an integrated producer from the same field.[3]

3. The willingness to explore and develop risky fields and areas may be different. That is, the stockholders of an integrated firm may be more (or less) willing for that firm to invest in high cost-high risk fields than investors in non-integrated oil firms.[4]

4. All other things equal, a non-integrated producer will be willing to pay more for the right to develop the same field than an integrated firm. Part of the tax benefits created by these differentials will be passed on to property owners via increased bonus and royalty payments.

5. All other things equal, capital might flow from integrated oil producers (and other sectors of the economy) to non-integrated oil producers.

6. All other things equal, integrated firms might invest relatively more of their assets in foreign investments than in domestic investments. That is, the change in the tax treatment of integrated oil producers over the past few years could have made direct foreign investment relatively attractive to similar domestic investments.[5]

7. All other things equal, integrated firms might invest relatively more of their assets in non-oil and gas related activities.

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[3] For an examination of the intertemporal allocative effects of taxation on mineral production in general see: Conrad and Hool (1981a, 1981b) and Conrad (1981 and 1982).

[4] How taxation affects the willingness of investors to bear risk is unclear. Increases in the level of taxation could increase or decrease the amount of risk borne by an investor depending on the investors' wealth and preferences about risk bearing. See Atkinson and Stiglitz (1980) for a discussion of this issue.

[5] I do not want to make too much of this point and empirical verification is certainly difficult. However, more stringent taxation of integrated firms on domestic investments clearly creates such an incentive. For an example of an attempt to measure such incentives, see Conrad (1980).

I do want to imply that the results of these incentives will be dramatic or that the integrated companies will close as a result of this differential treatment. They have not and they will not. However, the items listed above are some of the incentives that will be created in a competitive market like the one in oil and gas. Furthermore, there is every indication from the structure of the differentials in tax treatment that the share of domestic investment in oil and gas exploration and production on the part of the non-integrateds will increase. Some tentative evidence (suggestive but not conclusive) indicate such a trend. Table I contains the relative share of exploration and development expenditures of larger oil companies and independents.[6] As shown, the proportion of total expenditure in this category undertaken by "larger companies" has decreased relative to the industry as a whole, particularly since 1975. This trend is further indicated by the information contained in Table II. The figures in this table represent the proportion of industry assets held by various segments of the industry on an annual basis. As shown the share of assets held by the largest eight companies (in this case ranked by total value of crude oil production) has fallen rather consistently over the past few years.

The net effect of such a change in the composition of the domestic market if they are created by the tax differentials depends on several factors. First, as these tax differentials filter through what I believe to be a competitive market two results will occur in all likelihood: 1. there will be a direct substitution of investment by non-integrated producers for that which would have taken place by the integrated firms; and 2. there may be an increase in the total supply of domestically produced crude oil and gas (at least there will be increased investment) on the part of the industry as a whole relative to what would have been the case if all segments of the industry were treated in the same manner as the integrated firms.[7]

Second, at least part of these tax differentials will be capitalized in asset values. The relative price of oil drilling equipment might rise and I believe that the market price of future prospects will rise. This will occur because owners of potential plays will realize that some parties will be willing to pay more for these properties because of the differentials in tax treatment and will demand a higher payment for the drilling rights either in the form of bonus payments and/or royalties.[8] Given the fact that future drilling will in all likelihood be proportionately higher on federal tracts (both on- and off-shore), the federal government itself might recapture part of the tax benefits which it initially granted.[9]

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[6] It is cited in the references to Table I that the definition of non-integrated and larger companies may not coincide with taxation definitions of integrated oil companies and independents.

[7] The opposite would be the case if the integrated firms were treated on par with the non-integrated producers.

[8] In the extreme case where the supply of drilling rights is completely inelastic the value of these rights will increase a dollar for every dollar decrease in the taxes which would have been paid.

Fourth, it is possible that these tax differentials could cause a substitution of higher cost production for lower cost production. That is, depending on the structure of production and the geological characteristics of a particular deposit, any incremental production could cost more than the foregone production from existing sources. This is particularly true in the case of gas under the current price control regime where "new" gas from high cost sources is not controlled but gas from existing sources is controlled. The combination of differential tax incentives and the price control could create a direct substitution of higher cost gas for lower cost gas.

Finally, the impact of these tax differentials (either in terms of increased supply and/or the price of crude oil) will be limited by the fact that the market price of crude oil is determined in world markets. In 1982 proven reserves in the United States accounted for only about 5.1% of total free world proven reserves.[10] Given this small share of a world market it is not likely that U.S. tax policy designed to affect the price of a factor input will have any substantial long run influence on either the price to the consumer or on the total allocation of capital in this sector.

### 2.2 Examples Based on Willingness to Pay

In order to illustrate the potential effects of the tax differentials described above, consider the situation where there exists a geographical area indicating the presence of oil. Suppose that several companies (both integrated and non-integrated) are considering this investment. Suppose also that, regardless of who ultimately produces from the area, the gross-of-tax but net of inflation income stream will be equal. In a competitive economy the present value of this gross of tax cash flow will be equal to the value of the asset in the ground.[11] Define this present value as Y.

In the absence of taxation (or in the presence of neutral taxation), we can expect that potential producers would be willing to pay the same amount of money for the rights to explore and to develop the tract.[12] However, taxes do matter and the differentials in the tax treatment among the potential producers might create differences in their willingness to pay for the investment.

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[9] Given the tax treatment of private royalty interest, the net result of these interactions could be ambiguous, since the individuals could be taxed differently than either the integrated firms or the non-integrateds.

[10] Based on statistics cited in The Oil Producing Industry in Your State: 1982 Petroleum Independent Publishers, Inc. for the Independent Petroleum Association of America.

[11] As I noted in the Introduction, this work is based on Harberger (1955, 196.). Therefore, similarities in his text and mine are almost unavoidable, particularly with respect to notation which I have adopted almost completely. This footnote will serve as the basic reference for the analysis in this subsection.

Under the current tax laws the "net-of-tax" present value of this tract to an integrated corporation will be equal to:[13]

$$C_m = \frac{Y(1 - w - t + tw)}{1 - t(\alpha_1 d_1 + .85d_2 + .15\alpha_2 d_2 + \alpha_3 d_3 + \alpha_4 d_4 + \alpha_5) - Z\alpha_3}$$

where $\alpha_1$ = share of costs attributable to cost depletion

$\alpha_2$ = share of costs attributable to IDC's

$\alpha_3$ = share of costs attributable to 5 year ACRS property

$\alpha_4$ = share of cost attributable to buildings

$\alpha_5$ = share of cost attributable to other costs which are immediately expensed: e.g. abandoned losses

$d_1$ = present value of cost depletion deduction

$d_2$ = present value of IDC's amortization

$d_3$ = present value of 5 year ACRS property deduction

$d_4$ = present value of building depreciation deduction

t = tax rate = 46%

Z = investment tax credit rate: 10%

w = Windfall Profits Tax rate measured as a proportion of cash flow. Thus, $\frac{.15(P-\bar{P})}{P} < W < .94$

with P = field price of crude

$\bar{P}$ = adjusted price plus state severance taxes.

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[12] Differences may exist among producers with respect to preferences toward risk, the degree of current portfolio diversification, etc. However, these factors will reflect individual (and/or corporate choice) which can be expected in a well-functioning economy. Therefore, these factors will not enter the current analysis.

[13] Details of how these equations were derived and the values of the parameters are contained in the appendix to this testimony.

On the other hand the "net-of-tax" present value to a non-integrated producer will be equal to:

$$C_I = \frac{Y(1 - v - t + tw + te)}{1 - t(\alpha_2 + d_5 + \alpha_3 d_3 + \alpha_4 d_4) - Z\alpha_3}$$

where e = percentage depletion rate measures as a proportion of cash flow.

Thus $.15 < e < .5Y$

Other variables previously defined.

The ratio of $C_I$ to $C_M$ (i.e.: $C_I/C_M$) will thus provide a measure of the difference between the two potential producers' willingness to pay (measured as a proportion) created by the variation in federal tax treatment. Some calculations are provided in Table III. The results were derived assuming a 6% real discount rate and a 6% inflation rate.[14] The values of other parameters used in these calculations are contained in the appendix to this testimony. The proportion of average cost to price is an important variable because limitations for both the Windfall Profits Tax and percentage depletion for the independent producer are determined with respect to operating income.[15] The field price along with the adjusted base price determine the portion of revenues subject to the Windfall Profits Tax.

Table III.A contains the results computed by assuming that the independent producer pays the Windfall Profits Tax at the same rate as the integrated producer. In order to interprete this table a value of 1.0 implies neutral tax treatment. A value greater than one implies that independents are willing to pay more than an integrated firm because of differences in tax treatment. As shown, in every case the independent producer will be willing to pay more than the integrated producer. For instance, when the ratio of average cost to price is equal to one-half and the field price is $30/barrel, the independent will be willing to pay 22% more for this prospect than the integrated firm.

The first row of Table III.A is equivalent to the elimination of the Windfall Profits Tax.[16] Therefore, this row gives an indication of the tax benefits of percentage versus cost depletion and the more liberal treatment of IDC's. Two patterns are evident from an examination of the table. First, the independent's willingness to pay relative to the integrated firm increases as the ratio of average cost to price increases (the profit margin decreases). Second, the independent's willingness to pay more relative to the integrated firm increases as the field price increases.

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[14] Several computations were made for combinations of field prices, base prices and rates of inflation. Variation in the rates of inflation did not influence the results significantly. Variation in field prices and base prices generated the same pattern which is evident in Table III.

[15] The Windfall Profits Tax is limited to 90% of income, while percentage depletion is limited to 50% of income.

[16] Since the field price is equal to the adjusted base price the windfall profit is equal to zero.

This pattern is even more pronounced in Table III.B where it is assumed that the independent is exempt from the Windfall Profits Tax (e.g. a stripper well). This pattern results in large measure because of percentage depletion and the Windfall Profits Tax. Both the Windfall Profits Tax and percentage depletion are measured as proportions directly related to the field price. Therefore, as costs rise relative to price the dollar value of percentage depletion as a proportion of profits increases. This in turn increases the net-of-tax profit margin for the independent (i.e. an additional dollar increases the profit margin [measured as a proportion] more when the profit margin is 10% than when it is 50%). The Windfall Profits Tax works in the opposite direction. That is, as cost rises relative to price the Windfall Profits Tax decreases the net-of-tax margin for the integrated firm in Table III.B and for both firms in Table III.A. In Table III.A this effect is offset in part by the presence of percentage depletion for the independent.

One additional implication can be drawn from Table III. As market forces work to equalize net-of-tax returns there will be a tendency for independents to specialize in high-cost-low-output wells relative to the integrated firms because of the incentives created by the differences in tax treatment. These wells will be worth relatively more per dollar of investment even for the independent.

## 2.3 The Potential Benefits

The efficiency costs outlined above must be weighed against any potential arguments in favor of retaining such differentials. I believe that two types of arguments could be put forth to support differential taxation. First, there might be the desire to increase the level of competition and increase output. Second, smaller producers may have limited access to capital markets relative to the larger integrated companies, which through no fault of the majors, effectively limits competition. I am not convinced by these arguments.

The fact that the major oil companies are large and vertically integrated does not imply that they are non-competitive. Furthermore competition is not measured by the number of firms in an industry. Even if the majors could and would attempt to exercise control over all aspects of the market it is questionable whether differential tax treatment would provide a remedy. Tax incentives are by their very nature anti-competitive. Only those with income to shelter are able to take advantage of the tax shields, creating an advantage over firms who are unable to take advantage of them.

Two things might be noted with respect to the issue of access to the capital markets. First, if firms are able to take advantage of the tax shields, then these firms have been able to raise capital sufficient to generate taxable income. Second, an efficient competitive market may create difficulties for a firm in raising capital. That is, relative to other investments, potential investors may simply prefer to put their money in other assets instead of investing their scarce capital in an oil firm.

## 3. Interindustry Allocation

Any move to close the intra-industry differentials in the oil and gas industry must be considered in the context of overall tax policy. That is, there are numerous ways to eliminate the intra-industry differentials including: 1. reduce the level of taxation on the integrated firms to that currently afforded by non-integrated firms and 2. increase the level of taxation of non-integrated firms to that of the integrated firms. In order to illustrate the type of inter-industry effects from any change in the taxation of the oil and gas industry, consider the following example. Suppose a non-oil and gas firm is considering an investment with the same gross of tax cash flow as the oil tract discussed in the previous section. This investment is composed to possible two assets: 1. buildings and 2. five year ACRS property. Like the oil and gas investment, it will be assumed that competition will equate the willingness to pay for the investment with net-of-tax present value. That is:

$$Co = \frac{Y\,(1 - t\,)}{1 - t(\alpha_1^* d_1 + \alpha_2^* d_2) - z\alpha_1^*}$$

where: $\alpha_1^*$ = share of assets invested in 5 year ACRS property

$\alpha_2^* = (1 - \alpha_1^*)$ = share of assets invested in buildings

$d_1$ = present value of depreciation deductions on 5 year assets

$d_2$ = present value of depreciation deductions on buildings

$t$ = income tax rate

$z$ = rate on investment tax credits

$Co$ = willingness to pay

Table IV illustrates the possible effects of changing the current tax treatment of oil and gas relative to the investment described above. Three alternative asset mixes were chosen in order to measure the potential variation across asset groups; i.e. 1. 100% buildings; 2. 50% buildings, 50% five year property; and 3. 100% five year property. Computations are also presented for three different inflation rates: i.e. 0%, 6% and 10%.[18] The column headings could be considered possible policy options: 1. tax all oil and gas investments using the rules currently available for the integrated firms (increase the level of taxation on independents); 2. treat all oil and gas investments using the rules currently available for independents (decrease the level of taxation on integrated firms); and 3. eliminate the Windfall Profits Tax and treat all oil and gas investments using the rules currently available for independents.

In almost all cases, the oil investment generates a higher willingness to pay than any combination of other assets. The exception is the 100% five year property case using the tax rules currently afforded the integrated firm. Therefore, if the tax laws were changed in a manner whereby independents would be afforded the same treatment as currently afforded the integrated firms, then five year machine intensive investments could be treated more favorably than oil and gas investments. On the other hand, oil and gas investments would still be treated more favorably under the tax law than almost any other asset combination presented in the table.

One possible inference from this table might be to move toward neutral treatment in the oil and gas sector by treating everybody else in the sector like the integrated firms. However, caution should be used in making such an interpretation. Federal tax policy has never been neutral between assets and between industries. Table IV clearly shows this fact. If all other assets were treated in a neutral manner then the value of each ratio in the table would be equal to a constant. Consequently there is no standard by which to judge the best possible course for the oil and gas industry. Should oil and gas investments be taxed on par with the construction industry? the steel industry? or the retail trade sector? That is, without a standard for determining what the effective rate of taxation should be for all assets (a neutral position), trade-offs between sectors will be a necessary part of the policy process. However, even with the current variation in tax treatment across industries, there are few things this Committee might consider with respect to oil and gas.

First from an economic perspective, intangible drilling costs are capital expenditures. Therefore, based on first principles such capital expenditures should be treated on an equal basis with all other capital investments. If the goal of federal policy is to move toward cash-flow accounting then immediate expensing of all assets might be appropriate. However if the purpose of federal tax policy is to impose a tax on the returns to invested capital, then there is no tax policy reason to allow this type of expensing.

Second, immediate expensing of IDC's alone, cannot force the effective tax rate on marginal equity investments below zero.[19] If any single factor is responsible for the relatively low (and even negative) measured marginal tax rates in this industry it is percentage depletion. The major reason for this is that percentage depletion is the only deduction related to a capital asset which is not based on some measure of actual cost. That is, percentage depletion, being related to the value of production, creates the possibility that the producer may be able to write-off more than the value of the asset during its life. I believe that few, if any, other assets are afforded such liberal treatment. I can think of only one economic justification for such treatment. Because cost depletion is based on historical cost, this deduction may not be sufficient to recoup the losses incurred on account of inflation. However, it appears to me that this is an argument for indexation of the income tax system in general and not for the special tax treatment of this particular group of assets. Alternatives to this present treatment include: 1. immediate expensing (cash-flow treatment); 2. accelerated treatment similar to ACRS; 3. unit of production (or cost depletion).[20] Any of these methods would put these assets on a more comparable basis with other types of investments. Perhaps the elimination of percentage depletion could be timed to coincide with the phase out of the Windfall Profits Tax.

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[18] The method of calculation is presented in the appendix.

[19] It is well established that immediate expensing of assets is neutral in the sense that the tax on a marginal investment is zero.

Third, while the provisions of the federal income tax law might work to the benefit of the producer in this sector, the Windfall Profts Tax works in the opposite direction. Since the tax is an excise tax measured on the basis of difference in the world price and a base price adjusted for inflation, the operator perceives this tax as a reduction in his gross revenues. That is, this tax does not directly affect the operator's cost of capital. Rather, the tax reduces the demand for capital at a given price via an incentive to decrease output.[21] The net effect of tax is to offset, in part, the incentives created by the income tax.[22]

Finally, much of the discussion over tax incentives in the oil and gas industry has focused on the need to increase the production from domestic reserves and thereby reduce dependence on imports. If these goals are in public interest, then the social value of crude oil and gas is lower than its current market price. This fact, if true, would indicate the need for policies which would directly increase the price of crude oil to its social value. However, the current tax incentives designed to lower the price of one factor input in the production process, will tend to lower the market value of crude oil, if any price change occurs. This would then drive the market value of crude oil further below its true social value. In addition, income tax policy will create different incentives for the same producer at different points in time as well as different incentives to different producers at the same point in time. Therefore, given the weak link between cause and aggregate effect, I do not feel that differential income tax treatment designed to change the price of an input is necessarily a desirable method for increasing domestic production.

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[20] If percentage depletion is eliminated for oil and gas, than it should be eliminated for other natural resources as well.

[21] Furthermore, no additional substitution effect is created between capital and labor by the Windfall Profits Tax.

[22] A similar statement can be made about price controls on natural gas. However, both the Windfall Profits tax and the price ceilings on natural gas have exemptions and lower rates (or ceilings) for certain types of production which tend to reduce the neutralization of the incentives.

## Appendix

The calculations presented in the text are based on the work of Harberger (1955, 1961). In general, the price of an asset will be equal to the present value of the net-of-tax cash flow generated by the asset in a competitive market. That is:

$$C = Y - T$$

where: C = Cost (or willingness to pay for the asset)

Y = Present value of the gross of tax cash flow

T = Present value of taxes paid.

The value of T can differ between assets according to the tax provisions. The calculations presented in the text are based on the current provisions for particular groups and assets as I understand them.

Values used in the calculations are presented in Table A.1. The present value of the depreciation deductions were calculated by computing the discounted value of the deduction at each point in time using the gross-of-inflation discount rate. The life of the well was assumed to be 15 years. Values for shorter well lives were computed. However, the results are not very sensitive to this parameter.

## Table I

### Share of Exploration and Development Expenditure*

(Measured in percent)

|  | Larger Companies | Independents |  | Larger Companies | Independents |
|---|---|---|---|---|---|
| 1961 | 60.4 | 39.6 | 1971 | 70.3 | 30.7 |
| 1962 | 64.4 | 35.6 | 1972 | 65.2 | 34.8 |
| 1963 | 59.4 | 40.6 | 1973 | 64.8 | 35.2 |
| 1964 | 63.3 | 36.7 | 1974 | 64.0 | 36.0 |
| 1965 | 67.6 | 32.4 | 1975 | 66.6 | 33.4 |
| 1966 | 70.4 | 30.6 | 1976 | 59.6 | 40.4 |
| 1967 | 73.6 | 26.4 | 1977 | 62.4 | 37.5 |
| 1968 | 75.8 | 24.2 | 1978 | 58.4 | 41.6 |
| 1969 | 72.1 | 27.9 | 1979 | 56.1 | 43.9 |
| 1970 | 65.3 | 34.68 | 1980 | 56.7 | 43.3 |

*Source: The Oil Producing Industry In Your State: 1982. Petroleum Independent Publishers for the Independent Petroleum Association of America.

From the sources cited in the text it is not clear whether Exploration and Development Expenditures are calculated on a domestic or world wide basis. Also no definition of "Larger Companies" is given. Therefore, categories may not conform with tax classifications.

## Table II

### Share of Assets Owned by Various Groups in Domestic Oil Industry*

(Measured in percent)

| Year | Eight Largest Co. | 9-32 | All Other |
|---|---|---|---|
| 1973 | 47.9 | 28.1 | 24.9 |
| 1974 | 47.0 | 27.9 | 25.0 |
| 1975 | 45.9 | 28.0 | 26.0 |
| 1976 | 45.5 | 27.4 | 27.1 |
| 1977 | 43.2 | 28.9 | 27.9 |
| 1978 | 41.6 | 29.7 | 28.7 |
| 1979 | 42.0 | 31.5 | 26.5 |
| 1980 | 40.3 | 33.1 | 26.6 |
| 1981 | 38.3 | 32.4 | 29.3 |

*Source: Annual Survey of Oil and Gas, U.S. Department of Commerce, Bureau of Census (various years).

## Table III

## Ratios of Willingness to Pay by Independents to Willingness to Pay by Integrated Firms under Alternative Assumptions*

### A. Independents Pay Windfall Profits Tax

| Field Price | Proportion of Average Cost to Price | | | | |
|---|---|---|---|---|---|
| | 0 | .25 | .5 | .75[2] | .9 |
| 25[1] | 1.10 | 1.14 | 1.22 | 1.39 | 1.39 |
| 30 | 1.10 | 1.14 | 1.24 | 1.44 | 1.53 |
| 35 | 1.10 | 1.15 | 1.24 | 1.47 | 1.70 |

### B. Independents Exempt from Windfall Profits Tax

| Field Price | Proportion of Average Cost to Price | | | | |
|---|---|---|---|---|---|
| | 0 | .25 | .5 | .75[2] | .9 |
| 30 | 1.13 | 1.18 | 1.29 | 1.54 | 1.85 |
| 35 | 1.15 | 1.21 | 1.34 | 1.68 | 2.43 |

*Assumptions: Adjusted Base Price + State Severance Tax Adjustment = $25/barrel

Rate of Inflation = 6% per annum

See Appendix for other assumptions

[1] A $25/barrel field price implies no party is liable for the Windfall Profits Tax.

[2] 50% Profit limitations on percentage depletion becomes effective.

## Table IV

## Ratios of Willingness to Pay: Integrated Firms, Independent Firms, and Various Classes of Other Assets* Under Alternative Inflation Assumptions

### 6% Inflation

| | A<br>Integrated | B<br>Independent Windfall Profits Tax Applies | C<br>Independent Windfall Profits Tax Does Not Apply |
|---|---|---|---|
| 1<br>100% Building | 1.24 | 1.42 | 1.46 |
| 2<br>50% Building<br>50% ACRS Property | 1.08 | 1.24 | 1.28 |
| 3<br>100% ACRS Property | .93 | 1.07 | 1.1 |

### 0% Inflation

| | A | B | C |
|---|---|---|---|
| 1 | 1.14 | 1.29 | 1.33 |
| 2 | 1.02 | 1.15 | 1.18 |
| 3 | .89 | 1.00 | 1.03 |

### 10% Inflation

| | A | B | C |
|---|---|---|---|
| 1 | 1.27 | 1.48 | 1.51 |
| 2 | 1.12 | 1.29 | 1.33 |
| 3 | .96 | 1.11 | 1.14 |

| *Assumptions: | | |
|---|---|---|
| | Base Price Plus State Severance Taxes: | $25 |
| | Field Price: | $30 |
| | Cost to Price: | .25 |

Table A.1

Parameter Values Used in Calculations

| Symbol | Definition | Value |
|---|---|---|
| $t$ | Tax Rate | .46 |
| $W$ | Windfall Profits Tax | .15 |
| $\alpha_1$ | Share of C deducted for cost depletion | .0765* |
| $\alpha_2$ | Share of C deducted for IDC's | .3315* |
| $\alpha_3$ | Equipment's share | .09* |
| $\alpha_4$ | Building's share | .06* |
| $\alpha_5$ | Other costs immediately expensed | .442* |
| $Z$ | ITC | .1 |
| $P$ | % Depletion | .15 |

*Based on values used in Gravelle (1983)

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Mr. DORGAN [presiding]. Next we will hear from Professor Arthur Wright, chairman, Department of Economics, University of Connecticut. Mr. Wright.

## STATEMENT OF ARTHUR W. WRIGHT, PROFESSOR AND DEPARTMENT HEAD OF ECONOMICS, UNIVERSITY OF CONNECTICUT, AND VISITING SCIENTIST, ENERGY LABORATORY, MASSACHUSETTS INSTITUTE OF TECHNOLOGY

Mr. WRIGHT. Thank you, Mr. Chairman.

I am Arthur W. Wright, professor and department head of economics at the University of Connecticut, and visiting scientist at the Energy Laboratory of the Massachusetts Institute of Technology. I am also a member of the board of directors of Tax Analysts, Inc., a public interest group based in Arlington, Va. The views expressed in this statement are my own, of course, and are not meant to represent those of the University, the Energy Laboratory, the Institute, or Tax Analysts.

Thank you for inviting me to appear today to discuss the tax treatment of producers of oil and gas. This subject and I are old acquaintances. Between 1972 and 1976, a colleague, James C. Cox, and I wrote five papers, two pieces of testimony, and a long report for the U.S. Treasury on the subject. In 1981, I studied the possible effects of the special tax treatment of corporate income from oil and gas on oil companies' investment behavior, particularly their acquisitions of other firms.

Fourteen years ago, I testified on the tax treatment of depletable resources before both the House Committee on Ways and Means and the Senate Committee on Finance. That year, Congress passed the Tax Reform Act of 1969, which—among other things—reduced the percentage depletion rate from 27.5 to 22.5 percent of gross income. Congress went further in the Tax Reduction Act of 1975, limiting percentage depletion to independent oil and gas producers and phasing down both the rate itself and the amount of eligible production. The bill of particulars for these hearings is in large part the vestige of the pre-1969 special tax treatment of oil and gas income.

I agreed with the direction if not the magnitude of the changes Congress made in 1969 and 1975. No compelling case could be found on grounds of economic efficiency for subsidizing oil and gas production through the percentage depletion allowance and the expensing of intangible drilling costs. Nor did those special provisions look very good on the different grounds of cost effectiveness. In 1969, percentage depletion and intangibles expensing did not appear cost effective in promoting either of two goals, increased domestic petroleum reserves or increased domestic petroleum output—hence reduce oil imports. For the tax revenues lost, there seemed to be more effective ways to pursue both goals. Subsequent research of my own and by others bore out the 1969 impression.

Much has changed since 1969, and even since 1975, both in energy markets and in U.S. tax treatment of corporation income. In preparing this statement, I asked myself whether the changed circumstances were cause to alter my earlier views on the special tax provisions for oil and gas. The answer is no: What is left of those provisions today represents neither good tax policy nor good energy policy. Therefore, it would be good public policy to repeal them and apply uniform tax treatment to all domestic producers of oil and gas. Congress should finish the job it began in 1969 and almost completed in 1975.

The case for this conclusion consists of six points:

1. The special tax treatment of oil and gas creates an incentive, relative to uniform tax treatment, for scarce resources to flow into the domestic oil and gas industry.

The only conceivable reason to create such an incentive is security of oil supply. But the special tax provisions for oil and gas are not cost effective at increasing oil security when compared with a simple stockpile program. I shall return to this point at the end of my statement.

2. The special tax treatment of oil and gas creates an incentive to restructure the extraction of oil and gas into smaller business units.

There are no efficiency gains from doing so in what is by all indicators a competitive industry, and the restructuring entails extra transaction costs. Without offsetting efficiency gains, these transaction costs are a pure burden on the U.S. economy.

3. The special tax treatment of oil and gas reduces the effective corporate income tax rate on that industry. It may thus partially offset the efficiency distortions from the corporate tax, which is well known to act as an excise tax on one factor input, capital. Moreover, any offset will be relatively large in oil and gas, because that industry is among the most capital-intensive of U.S. industries.

However, a piecemeal offset to the corporate income tax, such as percentage depletion and intangibles expensing, does not seem like good tax policy. Properly to deal with the distorting effects of that tax, we should consider more general remedies such as integrating it with the personal income tax.

By the same token, it wuld be good tax policy, if the piecemeal oil and gas provisions are repealed, to grant the industry the uniform tax treatment of its investment costs, such as investment tax credits and accelerated depreciation, that is now accorded to other industries.

4. The distorting effects of the special tax treatment of oil and gas have been defended as an offset to the inefficiencies caused by price controls on those goods. Efficient energy policy, however, demands decontrolling oil and gas prices, not partially offsetting one inefficient policy with another one. Happily, we have now decontrolled domestic crude oil prices and are lurching towards the decontrol of wellhead natural gas prices.

5. The distorting effects of the special tax treatment of oil and gas may partially offset the distorting effects of the crude oil windfall profit tax [COWPT]. That tax is indeed an odious policy on economic-efficiency grounds. It taxes neither profits nor windfalls, but rather imposes a differentiated excise tax on domestic oil production that curbs both current output and investment in new reserves. Any offset to it can't be all bad.

Once again, though, it is doubtful that a piecemeal offset to the COWPT makes for good public policy; better to work towards repeal of the COWPT itself. Moreover, vestigial percentage depletion and intangibles expensing may not offset the COWPT to a very great extent, because the same production that is eligible for the special tax provisions also qualifies for lower COWPT rates.

Note that the COWPT also contains an incentive to restructure oil and gas extraction into smaller units. Thus, the special tax provisions reinforce rather than offset this source of inefficiency in the COWPT.

As a rule of thumb, it is good tax policy to treat all firms equally; this would argue for removing the differential rates for small producers in both the COWPT and the special tax provisions. Having said that, however, I must observe further that it would be even better tax policy, and certainly better energy policy, to repeal the COWPT.

6. To now, I have focused mainly on economic-efficiency arguments. In point No. 1, I referred briefly to the different criterion of cost effectiveness. I now return to that criterion in making my final point.

Oversimplifying in the interests of brevity, my colleague James C. Cox and I found that, for the period 1959–72, the special tax provisions for oil and gas cost the Federal Government large amounts of tax revenue for not very much increase in reserves or output. Other policies—market-demand prorationing and the oil import quota—had larger impacts on reserves and output, and different measures would have preserved more of our domestic oil resources for use in case of emergency.

Today, there is no oil import quota, and market-demand prorationing no longer sets the price of oil in the United States. Real oil prices have risen sharply since 1972, and with them the real prices of natural gas and other substitutes for oil have risen as well. The 1969 and 1975 tax acts sharply cut the tax benefits obtained from percentage depletion and intangibles expensing. Finally, the corporate income tax has been greatly modified, mainly in the direction of reduced effective tax rates.

Unfortunately, the market disorder created by Federal price controls on oil and gas have sapped our ability to model statistically what is happening in the oil and gas industry. Thus, I cannot say with any certainty how much of an impact the vestigial tax provisions for oil and gas have on petroleum output and reserves under present-day conditions. They most probably have a small positive impact on both variables, holding constant market prices, price expectations, and other government policies. We should, though, remark one fact: This small positive impact is limited mainly to the very smallest producers, because percentage depletion and intangibles expensing affect the reserve and output decisions only of producers with daily outputs below 1,000 barrels a day. At the margin, production in excess of that rate is not affected by the tax provisions; above the cutoff rate of output, the tax benefits are a pure transfer of aftertax income to eligible producers.

As I noted earlier, the only conceivable efficiency reason why the government would want to modify market-determined petroleum reserve and output decisions is to increase the security of oil supplies. Greater oil security is usually interpreted in terms of having some form of insurance against sudden, large disruptions of normal supplies. Most economists now agree that markets will not provide the socially optimal amount of oil security, and that Government intervention is therefore warranted.

In its earlier version—national security in case of a war that cut off our access to foreign oil—oil security was offered as a defense of the pre-1969 special tax treatment of oil and gas. The argument was that the special provisions helped foster a strong oil industry. Most economists rejected that defense of percentage depletion and intangibles expensing before 1973.

What about today? Are the vestigial special tax provisions cost effective at improving the security of oil supplies in the conditions of the 1980's?

We lack solid statistical evidence, but there is a persuasive qualitative argument that they are not cost effective. Let us assume for the sake of argument that the tax provisions in question do in fact increase both petroleum reserves and output. The extra reserves would improve security of supply, to the extent they represent extra (or excess) capacity to produce oil on short notice. But to the extent the tax provisions also increase current petroleum output, they reduce such spare capacity. Raising current output depletes domestic oil reserves, and thus weakens future oil security. More precisely, it raises the cost of future security—hardly a desirable result.

Among economists who have studied the oil security problem, the consensus best policy by a magnitude is to build a special stockpile that will be held in reserve against a possible sudden, large disruption of foreign supplies. An example of such a stockpile is the U.S. strategic petroleum reserve. No alternative policy seems to come close to the cost per barrel of available excess capacity. And that includes the vestigial special tax treatment of oil and gas.

Thank you for inviting me to appear before you today to present the above statement.

Chairman **Rangel**. Thank you, Professor.

Professor Walter Mead, University of California.

## STATEMENT OF WALTER MEAD, PROFESSOR, DEPARTMENT OF ECONOMICS, UNIVERSITY OF CALIFORNIA, SANTA BARBARA, CALIF.

Mr. **Mead**. I am Walter Mead. I am professor of economics at the University of California at Santa Barbara.

I have a prepared statement which has been submitted for the record.

Chairman **Rangel**. Without objection, your full statement, Professor, will be entered into the record.

Mr. **Mead**. I would like to summarize that statement now.

You have heard a great deal in the past about how economists disagree. I would like to point out that there is virtually no disagreement on the matter of the principle of tax neutrality, taxes should be neutral both between industries, for example, between oil and coal or solar, but tax neutrality also applies to firms within an industry as between independents and integrated firms.

Why is there this uniformity of view among economists?

Businessmen make decisions on the basis of aftertax rates of return on investments. When Congress cuts tax rates for one industry relative to another, or one group of firms relative to another, that causes capital flows to be different. Capital will flow into the area on which taxes are more favorable because the aftertax rate of return on capital is raised.

For industries, that tax favoritism leads to output expansion and then lower prices. We have a long history of this in the oil industry. The history of percentage depletion allowance and intangible drilling costs goes back about 70 years to the time of World War I. These two tax features have been major tax subsidies. But we have been subsidizing a nonrenewable resource. Those tax subsidies have caused the price of products to be lower than they should be. It has led to very large cars, and wasteful use in general of this nonrenewable resource.

But it has also been a penalty to new industries like solar. When you subsidize small firms versus large, that runs the risk of keeping some inefficient firms in an industry and wasting the Nation's scarce resources.

The conclusion on theory is that there is virtually no disagreement on this. Taxes should be neutral. I don't think one can find a competent economist in the country today who would disagree with that generalization. But generalization is one thing, and people may wonder is there something about the oil industry that justifies a departure from this widely accepted generalization.

I have tried to explore some possibilities. One possibility calling for a departure from the principle is the suggestion that large firms might have market power, monopoly power, say, relative to smaller firms.

If this is so, then the proper way to go about it would be through antitrust activity to eliminate the monopoly power, rather than to use tax policy in that area.

But the second point is there is no evidence, to my knowledge, that large firms have monopoly power relative to smaller firms. This is a point that is very difficult to prove. It is difficult to prove because today we do have these tax distortions built in where small firms have tax advantages.

We have completed a study out at the University of California at Santa Barbara that does, however, address this point and if you will refer to table 1 on page 6 you will find some data from this study.

What we did was to study the record of bidding for Outer Continental Shelf oil and gas leases in the Gulf of Mexico from the beginning, 1954, through the year 1969. Then we had production data subsequently from those leases. There were a total of 1,223 leases issued and we estimated the rate of return earned by large companies versus small. We have defined "large" as the big 20 oil companies and the others are "all other companies."

What we found was that the big 20 companies actually earned a lower—not a higher—rate of return on their Federal leases.

The rate of return which they earned after all taxes was 10.66 percent, whereas, the smaller firms earned a slightly larger 11.15 percent.

You might notice also in table 1 that the large companies pay more for their leases, $2.3 million per tract, compared to $1.7 million for the smaller firms.

Notice under the head of "percent dry" that smaller firms apparently have a superior ability to determine whether or not a tract is productive. The percent dry tracts acquired by smaller firms is lower than that of the large firms. The results of the study indicate that we find no evidence that large firms have monopoly power or more properly, "monopsony" power in buying oil and gas leases and producing oil and gas in the Outer Continental Shelf.

In other areas there are lots of studies of competition in the oil industry. I have, for the benefit of the committee, footnoted those in a reference.

If I can summarize all of them it would be to the conclusion that there is no evidence of monopoly power in the domestic oil industry. Contrary to what the public often believes, the domestic oil industry is effectively competitive and it was effectively competitive prior to the introduction of these differential tax rates in approximately 1975.

So, on point 1, there is no support of the argument that large firms have market monopoly power.

One might try to make a second point that large firms have excessive political power relative to the small firms. Here, too, there is really not any support for the point. You can go back to the import quota period when import quotas were introduced in 1959 and look at the evidence of the testimony there and what you find is that large firms strongly opposed import quotas and the independents strongly support them. The independents won out, indicating their greater political power.

Furthermore, the subject matter of the hearings here today, namely, that the independents have tax advantages, is further evidence that the political power, if different between large and small, really is higher political power for the independents than the majors.

The third possible point is a little new development in what is called optimal tax theory and it is suggestive that if large firms have supply functions which are less elastic than small firms there might be some basis for differential taxes.

The problem with the point is there is no evidence of differential supply elasticities so the point is not supported by evidence.

Finally, there is a great temptation to argue that large firms are more efficient, that small ones can't compete and that unless the small ones are given tax subsidies they cannot survive.

Again, no evidence supports that statement. In fact, the little evidence we have suggests the opposite, that small firms do very well indeed.

The conclusions that I would draw, Mr. Chairman, are on page 7 and they are: No. 1, there is no supportable economic justification for differential tax rates in the petroleum industry. I think all panelists agree to this point.

No. 2, percentage depletion allowance for independent but not integrated firms is discriminatory and should be repealed in total.

No. 3, expensing of intangible drilling costs includes some differential conditions. These should be eliminated. Interindustry discrimination exists where other industries are required to capitalize and depreciate their plant and equipment investments, except where the value of an investment falls to zero. For oil and gas, investments that result in productive fields should be capitalized. Dry properties might be expensed when abandoned as at present.

No. 4, the windfall profit tax is disciminatory against the oil industrey relative to other industries. The tax is not a profit tax, but an excise tax and has the effect of reducing the net selling price of oil received by the producer. As a consequence, it discourages oil production from high cost-low selling price oil. Furthermore, it reduces the supply of capital available to the oil industry below what a neutral tax would allow. The windfall profit tax should be abandoned as soon as possible.

No. 5, as a second-best position, discriminatory rates by firm size class should be eliminated, preferably by lowering the rates applicable to integrated firms to equality with independent firms.

Thank you.

[The prepared statement follows:]

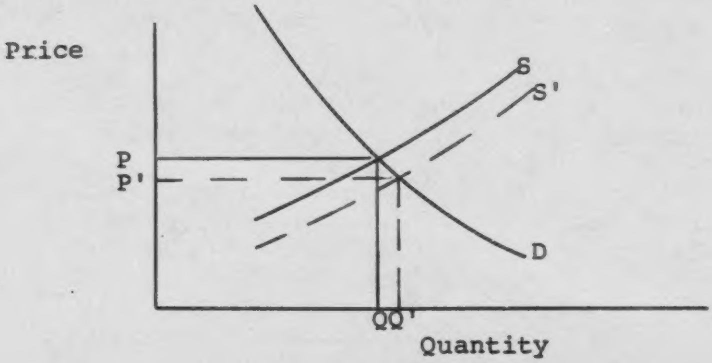
## STATEMENT OF WALTER J. MEAD, PROFESSOR OF ECONOMICS, UNIVERSITY OF CALIFORNIA, SANTA BARBARA, CALIF.

The purpose of this testimony is to examine the economic justification for differential tax rates between integrated versus independent (non-integrated) firms engaged in petroleum production, and between industries (petroleum vs. non-petroleum).

### ECONOMIC THEORY CALLS FOR TAX NEUTRALITY

There is wide agreement among public finance economists that taxation should be neutral between firms and industries. The reason for this unanimity is that differential tax rates lead to shifts in the flow of capital to the firms or industries favored by low tax rates, and away from those with higher tax rates. As a consequence of excessive capital flows into the favored firms or industries, product output is expanded and their prices normally decline, thereby sending incorrect signals to consumers. For example, both expensing of intangible drilling cost treatment of petroleum development investments, and percentage depletion allowance treatment of oil and gas production were developed around the time of World War I. Business decision makers then and now make their capital investment decisions on the basis of expected after-tax rates of return. When these two tax provisions were granted to oil and gas production, the immediate result was that after-tax rates of returns increased causing more capital to flow into petroleum development and production. This led to increased output and then to lower product prices until the after-tax profit on investment returned to equality with alternative investment opportunities having a similar risk. These reactions are shown in Figure 1. The effect of reduced tax rates is to shift the supply curve for the favored industry from S to S', and output to increase from Q to Q', leading price to fall from P to P'.

Figure 1--Effect of a tax subsidy on price and quantity.



## IF TAXES ARE NOT NEUTRAL, SCARCE RESOURCES ARE WASTED

The consequences of this favored tax treatment for oil are now apparent. Relatively low gasoline prices contributed to the well known American "love affair" with large automobiles. Low prices also led consumers to use their cars more than would have occurred had taxes been neutral and therefore higher for the oil industry.

This favored tax treatment and consequent lower prices for petroleum products lasted from the time of World War I until import quotas were introduced in 1959 and oil prices were artifically increased. But in the meantime, much of the damage had been done. Oil resources in the U.S. were depleted more rapidly than tax neutrality would have allowed, contributing directly to the "energy crisis" of the 1970's. This rapid depletion process was accelerated when import quotas were introduced.

While coal was awarded a depletion allowance, the net benefit to coal was much less than for oil because (1) the percentage depletion rate was lower for coal, and (2) the 50 percent of net profit limit was more restrictive for coal than for oil.[1] Thus, the greater tax benefit for oil led to increased use of oil (and natural gas) relative to coal.

Similarly, the tax benefits for oil and gas favored its use relative to solar, wind, and other substitute energy forms which had no similar tax subsidies, thereby retarding their introduction into the U.S. energy mix.

When Congress began allowing independent oil companies favorable tax treatment compared to integrated oil companies, it immediately made the smaller firms more profitable on an after-tax basis relative to larger firms. This action led capital to flow to the favored small firms relative to their larger competitors.

This discrimination by firm size distorted the market mechanism. From an economic efficiency perspective, ordinary market forces should be allowed to reward the most efficient and penalize the least efficient. When market forces are not allowed to perform this function, then the nation's scarce capital resources are inefficiently allocated with the result that our standard of living is lower than it could be. Prior to the introduction of discriminatory tax rates by firm size in the 1970's, the oil industry was composed of both large and small firms in effective competition. Markets shares in all sectors of oil production have shifted in favor of small firms as a result of discriminatory tax and other legislation.

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[1] G.M. Brannon (editor) "Studies in Energy Tax Policy," Cambridge, Mass. 1975, p. 14.

## IS THERE ANY ECONOMIC JUSTIFICATION FOR NONNEUTRAL TAXATION?

Although economic theory strongly supports the principle of neutral taxation, there may be special conditions which merit a departure from the principle. What might these conditions be?

1. If large firms have market power leading to competitive advantages for these firms, one might argue that Congress should impose higher taxes on large firms in order to offset their market power. There are two major problems with this argument. First, if evidence indicated large firm market power, the best corrective would be antitrust policy rather than tax policy. With competition restored, market power would disappear. Second, there is no convincing evidence that large firms in the petroleum industry have market power which yields high rates of return relative to small firms. To the contrary, there is some evidence that in Outer Continental Shelf (OCS) oil and gas production, small firms outperform their larger competitors.

A study of 1,223 OCS oil and gas leases sold by the Federal Government in the Gulf of Mexico over the years 1954 through 1969 indicated that the big 20 firms (rated by worldwide sales) earned a 10.66 percent return on their total capital outlays. Smaller firms earned a slighly higher 11.15 percent return. As shown in Table 1, the small firms paid substantially less for their leases, and fewer of those leases were dry. This record includes the period from 1954 through 1975 when large firms and small firms enjoyed the same percentage depletion allowance subsidy, and the absence of any windfall profit tax or differential tax rates through the year 1979. Due to the discounting process, the differential tax treatment that started in 1975 and was expanded in 1980 would have only minor effects on the rate of return calculation covering the larger period of time.

Table 1.—THE PERFORMANCE RECORD OF LARGE AND SMALL FIRMS IN THE GULF OF MEXICO FROM LEASES ACQUIRED FROM THE FEDERAL GOVERNMENT OVER THE YEARS 1954–1969.

| Firm size class | Number of leases | Average bounus per lease | Percent dry | Rate of return (percent) after taxes |
|---|---|---|---|---|
| All leases | 1,223 | $2,228,332 | 61.57 | 10.74 |
| Big 20 firms | 1,024 | 2,323,204 | 62.29 | 10.66 |
| All other firms | 199 | 1,740,377 | 57.90 | 11.15 |

Note.—This study was performed at the University of California, Santa Barbara, under a contract with the U.S. Geological Survey, Principal Investigator, Walter J. Mead. The production record was based on actual production and prices through the year 1979 with production and prices forecast through the point of economic close-down, not later than the year 2010. W. J. Mead, A. Moseidjord, and P. E. Sorensen, "The Rate of Return Earned by Lessess Under Cash Bonus Bidding for OCS Oil and Gas Leasees", forthcoming, The Energy Journal, 1983.

There have been many studies of competition in the domestic petroleum industry over a long span of time. The majority of them conclude that this industry is effectively competitive. The most authoritative is probably an analysis by the Federal Trade Commission which concluded as follows: "With regard to the three fossil fuels—crude oil, natural gas, and coal—the report concludes that concentration in production is moderate and lower than concentration in many other industries."[2]

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[2] Federal Trade Commission, "Economic Report, Concentration Levels and Trends in the Energy Sector of the U.S. Economy," Staff Report to the Federal Trade Commission, March, 1974, p. 147. In addition to the FTC studies, the following indicate that competition is effective in the oil industry: T. D. Duchesneau, "Competition in the U.S. Energy Industry" (Cambridge, Mass.: Ballinger Publishing Co., 1975); Richard B. Mancke, "Competition in the Oil Industry" in E. J. Mitchell, "Vertical Integration in the Oil Industry" (Washington, D.C.: American Enterprise Institute, 1976); R. O. Jones, W. J. Mead, and P. E. Sorensen, "Free Entry into Crude Oil and Gas Production in the United States, and Competition in the U.S. Oil Industry," "Natural Resources Journal," Oct. 1978); Susan M. Wilcox, "Joint Venture Bidding and Entry in the Market for Offshore Petroleum Leases," (unpublished dissertation, University of California at Santa Barbara, March 1975; J. W. Markham, A. P. Hourihan, and F. L. Sterling, "Horizontal Divestiture and the Petroleum Industry" (Cambridge, Mass.: Lippincott Co, 1977); D. J. Teece,

Continued

If market power existed in the domestic petroleum industry, one would expect that monopoly profits would accure to all firms in the industry and not to the large firms alone. In this event, differential tax rates would not solve the problem.

2. One might argue that large firms have excessive political power relative to their smaller competitors and that differential tax rates are justified to restore balance. The evidence suggests that the opposite is true. When oil import quotas were being debated in the 1950's the large firms testified in favor of free trade—it was their oil that would be subject to import limitations. The record as evident in Hearings conducted by the Office of Defense Mobilization clearly demonstrates that the independent oil producers strongly favored import restrictions and their view prevailed. In the case of market demand prorationing, small firms were protected by exemptions and large firms bore the main burden of output restrictions which brought about higher domestic oil prices. The differential tax rates which are the subject of this hearing offer further evidence that independents have superior political power.

3. Optimal tax theory holds that differential tax rates may be appropriate when the supply function of large firms is less elastic than those of small firms. A special tax might then be justified to correct for a "deadweight loss" that might otherwise occur. However, there is no evidence indicating that supply functions differ between integrated vs. non-integrated firms, let alone that the former are less elastic than the latter.

4. There is no support in economic theory which would suggest that large firms are more efficient than small firms (that there are economies of scale) and as a consequence should bear higher tax rates. This point is mentioned here because the argument might sound plausible or fair to laymen. Two counter points should be mentioned. First, there is no evidence that large firms are more efficient in oil or gas production. As indicated in the OCS record given above, the opposite may be true. Second, even if scale economies existed, they would not justify tax penalties. If maximum efficient size is penalized by government policy, then the production system becomes less efficient and the standard of living of the people is penalized. If scale economies extended to the point where only a few firms could survive and monopoly power was created, then corrective action in some form might be called for. Clearly, this is not the case.

### CONCLUSIONS AND POLICY RECOMMENDATIONS

1. There is no supportable economic justification for differential tax rates in the petroleum industry.
2. Percentage depletion allowance for independent but not integrated firms is discriminatory and should be repealed in total.
3. Expensing of intangible drilling costs includes some differential conditions. These should be eliminated. Interindustry discrimination exists where other industries are required to capitalize and depreciate their plant and equipment investments, except where the value of an investment falls to zero. For oil and gas, investments that result in productive fields should be capitalized. Investments in dry properties might be expensed when abandoned as at present.
4. The windfall profit tax is discriminatory against the oil industry relative to other industries. The tax is not a profit tax, but an excise tax and has the effect of reducing the net selling price of oil. As a consequence, it discourages capital flows into oil production from high cost-low selling price fields. Furthermore, it reduces the supply of capital available to the oil industry below what a neutral tax would allow. From a tax neutrality perspective, the windfall profit tax should be abandoned as soon as possible.
5. As a second best position regarding the windfall profit tax, discriminatory rates by firm size class should be eliminated, preferably by lowering the rates applicable to integrated firms to equality with independent firms.

Chairman **Rangel**. Thank you for your testimony.

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"Vertical Integration and Vertical Divestiture in the U.S. Oil Industry" (Stanford, California: Institute for Energy Studies, July 1976); R. O. Jones, "Vertical Integration, Cartel Coordination and the Petroleum Industry," (unpublished dissertation, University of California at Santa Barbara, Dec. 1977); Edward W. Erickson, Hearings before the Committee on Interior and Insular Affairs, U.S. Senate 93rd Congress, First Session, Part 1, 1974; A. E. Kahn, Hearings before the Committee on Interior and Insular Affairs, U.S. Senate, 94th Congress, first session, Part 1, 1974. For contrary views see John M. Blair, "Control of Oil" (New York: Pantheon Books, 1976), and F. C. Allivine and J. M. Patterson, "Competition, Ltd" (Bloomington, Indiana: Indiana University Press, 1972).

I turn the Chair over to Mr. Dorgan for questions.

Mr. **Dorgan**. Thank you, Mr. Chairman.

I would like to ask the panelists to give me some description from their perspective of the effect decontrol and the windfall profit tax have had on domestic production? It is kind of a broad question, but I will eventually get to the specifics of the windfall profit tax.

Mr. **Mead**. I would suspect we would be of one opinion on that.

If you eliminate or reduce in any way the burden of the windfall profit tax, the first effect would be, it would raise aftertax income and make investments in oil and gas production more profitable, and, as a result, there would be an increase in production.

Ms. **Gravelle**. I wonder if I might add to that.

My calculations suggested that the windfall profit tax alone—not decontrol—would probably have a relatively small quantitative effect on new oil investment, simply because at this point it has gotten to be quite small. The relationship between the base price and the selling price is pretty high. And it will be phased out over a period of time. And these are very long-lived investments.

So that, for example, I found the tax rate rising from, I think, 14 to 16 percent for integrated firms. And that is going to be a pretty small difference.

The rise in relative prices of oil, say, since 1973, was an enormous price change.

Mr. **Dorgan**. Mr. Conrad—I am sorry.

Mr. **Wright**. The simple answer to your question would be that decontrol spurred both output and investment, and the windfall profit tax cut effect. The net effect, I think we would agree, has probably been positive since 1981, or whatever date you want to use for reference.

Chairman **Rangel**. Mr. Conrad, in your testimony it seemed to me you were demonstrating empirically, with the studies you have conducted, that the special tax provisions for independents are inefficient, and, therefore, should be removed.

Is that a fair summary? If that is a fair summary, the question is, how does that relate to the larger question of competition that was raised by Congressman Watkins and Congressman Jones, and others? Perhaps this is not a quantitative thing, but, it is nonetheless, an important consideration.

Mr. **Conrad**. The first point you made with respect to my study, it is true that I do believe the differential taxation between the integrated firms and the nonintegrated firms is distortionary. That is not to say, however, that you should eliminate incentives for the small firms.

Another option to make things nondistortionary is to give the things to the large firms.

That is an issue of overall tax policy with respect to how you want to treat oil and gas as an industry as a whole.

Mr. **Dorgan**. In Mr. Wright's testimony, on page 2, in No. 2, you point out that the special tax treatment of oil and gas creates an incentive to restructure the extraction of oil and gas into smaller business units.

I assume you are talking about the special tax treatment for independents.

Mr. **Wright**. Yes, sir.

Mr. **Dorgan**. I assume you are talking about efficiency again. The larger question of competition is still important. In the previous testimony we have had about independents searching for oil, where some of the majors don't, and, therefore, creating the marginal supply that we might not otherwise have had, it might not be as efficient as some of the production that goes on by some of the majors, but isn't any less important.

Mr. **Wright**. I think we are using efficiency in two different senses. I am talking about the overall allocation of resources in the economy. I think unless one can demonstrate that you get some gain, it is better to avoid inefficiency. That is the broad general sense in which I used the term.

Several of the other panelists have indicated that there is wide agreement among economists studying the oil industry that there is a very high degree of market competition, and that, therefore, this should not be a concern of tax policy. I think it is a red herring to introduce the notion of competition in that industry in relation to the impact of these provisions on independents. I really don't think there is much gain or loss there, except the incentive to restructure firms at the margin where you have the option of staying small—there is an incentive to do so. And there may be some transaction costs there that we don't need to bear.

Mr. **Conrad**. The issue about competition, differential treatment, perhaps might be valid. But it seems to me that on economy it is always in a state of flux. Firms enter; firms leave. And the issue comes down to whether or not the Tax Code ought to institutionalize the segmentation in the industry.

Mr. **Dorgan**. Institutionalize what?

Mr. **Conrad**. Provide incentives to segment the industry into a smaller group of high-cost firms and a large group of low-cost firms. The most interesting thing that came out of the study that I completed is that the tax incentives at the margin seem to be indicating that even an independent producer with $100 or $1,000 to invest would prefer to invest that money into a high-cost low-profit margin operation than one that even has a higher profit margin because of the tax incentives. And that is one of the difficulties with the current differentiation in tax treatment.

Mr. **Dorgan**. I would like to ask another line of questions.

The various studies that I have seen and have been cited would suggest substantially different reinvestment characteristics between the major integrated companies and the independents. For example, there was testimony today that the independents reinvest to 105-percent.

I don't know whether that is an empirical study.

There was another group in town about 1 year ago that put out a statement that said the integrated companies, the major companies, reinvested something like 18 or 22 percent. I have no idea where that figure came from, nor do I have any idea of the validity of their study.

You thus have different groups alleging different things about reinvestment. If the numbers given us earlier about 105 percent reinvestment by the independents—is that factored into your judgments about whether or not these tax incentives to independents have stimulated that condition? Maybe I will ask Mr. Mead.

Mr. **Mead**. I don't know, either, where the 105 percent came from. It may have been a convenient kind of pulling out of the air somewhere.

Mr. **Dorgan**. Members of Congress don't do that. I suspect there is some empirical evidence somewhere.

Mr. **Mead**. I am not sure there is any difference between the independents and the majors on this score, both borrow money and reinvest.

The thing that we are all concerned about is that investment decisions are made on the wrong basis. If they are made on the basis of tax gimmicks, then the Nation has suffered a loss. One of the best illustrations comes out of the period of import quotas, and what became known as the small refiner bias. This was introduced in the early sixties, and then became part of the price control legislation. And what happened was you could build a small refinery and make a profit after taxes, even though on an ordinary economic justification basis you would lose money.

So, there were a lot of inefficient refineries built, and the Nation lost when this happened. Now, with decontrol, that bias is gone, and those refineries are generally going broke.

Here we have wasted a lot of our capital in inefficient processes. That is what is wrong with businessmen making decisions on the basis of discriminatory taxes. They are made on the basis of private tax gains where the taxes should be neutral so that businessmen make investments which produces gains for society greater than the costs of the resources used.

This is why all economists are opposed to these kinds of tax discriminations.

Mr. **Dorgan**. Anybody else like to comment?

Mr. **Conrad**. All industries—if you break up an industry into smaller components by asset size or what-have-you, and then look at them through time as the age distribution of the industry changes, then you are going to see some firms are reinvesting a larger percentage of their assets than other firms.

That generally—if that is an issue in terms of leverage, with respect to how the tax laws should be with respect to leverage, that is an issue of the development of the overall industry over time, and not with respect to specific aspects of that industry.

And so from my perspective, the fact that the independents reinvest 105 percent of their earnings, should have no bearing at all on the considerations of the tax laws.

Mr. **Dorgan**. We thank the panel for its testimony.

Might I say that I taught economics in college ever so briefly. It has not disadvantaged me in my work here in Congress.

We really appreciate the kind of testimony you have given us, empirical testimony, some very thoughtful analysis of what the tax code is, and what it ought to be. Our interest is really in trying to get all of these things in the record.

With respect to the 105-percent reinvestment, I am sure we will have a good opportunity to hear from independents and some of the studies that have been done, so we can analyze exactly what those numbers are and what they mean.

We certainly appreciate your testimony.

Chairman **Rangel.** I want to thank you and have you know that your observations certainly will be included in our report to the full committee. I hope you monitor our recommendations and feel free at your respective universities to respond to any recommendations the subcommittee makes. I what you to know that we welcome this type of oversight before we make any final decisions, because, as some of you have pointed out, sometimes political pressures substitute for sound tax policy.

We do expect that our academic community will assist us in reaching the right decision rather than just a political decision.

So, you may be hearing from some members who could not be with us today because they had to return to their home districts. So, the record will remain open for questions that may be directed to you.

I want all of you to rest assured your full statements will appear in the record.

Thank you again.

Our next panel is headed by the president of Petroleum Analysis, Ltd., from New York, Mr. Dillard Spriggs, and the senior partner of Hopkins & Sutter, from Chicago, Ill., Frederic W. Hickman.

Welcome.

## STATEMENT OF DILLARD P. SPRIGGS, PRESIDENT, PETROLEUM ANALYSIS, LTD., NEW YORK, N.Y.

Mr. **Spriggs.** Thank you, Mr. Chairman.

Let me say that I believe the subject of these hearings ought to be viewed in the context of the overall interests of the United States and its appropriate energy policy.

That policy, I think, should be to encourage the development of all fuels, all energy fuels. Oil and gas, I am sure you know, have long constituted the largest share of U.S. energy consumption.

Today, they make up over 60 percent. Because of this high importance, it is obvious that any governmental policies in the tax area or any other realm of public policy have important implications for U.S. energy supplies.

In this connection, I think it is important to note certain recent events in the U.S. oil economy which are affecting significantly the supply situation in the oil industry.

These developments include:

A sharp decline in drilling activity that has seen the number of employed drilling rigs reduced from around 4,500 near the end of 1982 to about 1,800 today. It is likely that the number of wells drilled will fall to less than 65,000 this year from 86,000 in 1982.

This reduction and the fact that no important new oil fields of size are going to be placed in production either this year or next means that U.S. crude oil production will fall about 100,000 to 150,000 barrels per day in 1983.

As a result of these developments, the progress that the U.S. petroleum industry has made in recent years in reducing imports of foreign crude oil and refined products will come to an end in 1983. Not only will it end; that progress will be reversed. Imports, excluding purchases for the Strategic Petroleum Reserve, will increase this year by an estimated 500,000 barrels per day.

This estimate, I may add, is based on a limited increase in U.S. oil demand in 1983 over 1982 of only 1 percent. If the increase should be larger than that, due to a stronger economic recovery than now foreseen, or for any other reason, the requirement for imports will increase further.

I conclude from developments now underway that the United States is entering a new phase in the evolution of its oil economy. It will be one in which its own production of oil will continue to fall off—probably moderately between now and 1985.

Then, in the rest of the 1980's, the rate of decline will accelerate rapidly unless the exploratory effort between now and then is increased substantially and is uncommonly successful in adding new reserves quickly. Output from the Prudhoe Bay field on the North Slope of Alaska, now 1.5 million barrels per day, or 18 percent of U.S. crude oil production, will fall after 1986 at a relatively rapid pace and will be difficult to replace.

This means that imports from overseas will be growing at a substantial rate during the remainder of the decade.

The conclusion that is logical to draw from this situation is that U.S. energy policy should be directed toward measures—both in the tax realm and elsewhere—that help to counteract the future increases in the use of foreign oil.

Now, let me turn to the windfall profit tax. I believe it has been true since this measure was enacted—and is even more true as we face the rest of the 1980's—that exploration for new oil should be encouraged. For purposes of both tax and energy policy, that means that there should be no windfall profit tax on new oil production.

As one examines the history of oil industry developments which led up to the enactment of the windfall profit tax, I believe that windfall profit tax was the price that the oil industry had to pay to get out from under price controls. As a result of the increase in the world oil price in the years after the imposition of controls, the removal of control regulations represented windfall gains on oil found and developed 10 years or more earlier.

However, the decline rate in oil and gas production is relatively rapid, making it necessary to phase out the WPT. This Congress did, although one can argue that the phase-out period was extended too long into the late 1980s.

Unlike old oil, no windfall gain is possible on newly discovered oil reserves. Moreover, today's economics for finding and developing new oil are relatively costly. And, the price of crude oil has been falling. For this reason, not to mention the deteriorating domestic supply situation that is likely to characterize the rest of the 1980s, I believe that the WPT on new production is a misplaced measure.

It is, of course, true that the Economic Recovery Tax Act of 1981 reduced the rate of WPT on newly discovered oil from the 1981 rate of 30 percent downward in stages to 15 percent in 1986 and thereafter. However, in my opinion, it should have been removed completely.

As to the issue of differentiation in the tax treatment of integrated and nonintegrated producers, there is one overriding consideration which indicates that nonuniform application of taxes should be minimized. In terms of the national interest and the need for increasing domestic oil and gas supplies, all barrels of oil and all 1,000 cubic feet of natural gas are required, whoever produces them. Any unit produced adds to supply.

Therefore, there is no need to impose different rates of tax on producers. Rates or exemptions, in general, should be uniform.

I believe that the law regarding expensing of intangible drilling costs—IDC—should be common to all producers. Nonintegrated companies may not expense 100 percent of their IDC's. Integrated companies are limited to expensing 85 percent of their IDC's, and write off the remaining 15 percent over 36 months. There is no fundamental reason for this differentiation.

In this connection, it is useful to examine the record of exploration success and new reserve additions in the United States by the major integrated oil companies and by the rest of the industry. Over the 4-year period 1978-81, 19 of the major companies accounted for over 60 percent of the reserves of crude oil and natural gas liquids found in the United States.

Over the same period, these same companies found 37 percent of the natural gas found. The remainder was found by a very large array of companies, most of which were nonintegrated companies.

While finding rates differ among companies and groups, it takes all participants in the industry to explore for and discover oil and gas in the United States. There is no good reason to apply different rates of exemption on IDC expensing to the type of company that takes on the job of exploring for oil or gas. This is particularly true in light of the fact that new reserve additions by the entire industry are not replacing annual production as these figures show.

The shortfall reflects the fact that new oil resources are difficult to find and that the search for them requires very large expenditures. The experience of the last several years reveals that the cost of finding and developing oil and gas reserves has increased very sharply. For 20 of the leading U.S. oil companies shown in table 3, finding and development costs increased as much as 2.65 times between 1978 and 1982, reaching $13.84 per barrel last year.

Oil finding costs at the moment are declining, mainly because of the great oversupply of drilling rigs which has resulted in reduced contract drilling rates. It may be that finding and development costs will tend to stabilize for this reason but that will depend on discovery rates of new oil and gas reserves.

And as just indicated, discovery of new reserves is difficult. The industry will not add as much to reserves as it did when drilling activity was at high levels. Furthermore, the exploration effort is moving into frontier areas in Alaska and the Outer Continental Shelf where costs are a multiple of those in customary onshore areas.

In short, capital formation in the oil industry is no easy task, and it may pose serious problems for oil and gas producers as they move into the high-cost frontier areas. This is a further reason for not differentiating in the tax treatment of integrated and nonintegrated companies.

Under current legislation, stripper wells owned and produced by nonintegrated companies are exempt from the WPT. I believe that this exemption should also be applied to integrated companies for the same reasons I have already cited; namely, that producers of the same oil under the same circumstances should be subject to uniform taxation applied commonly to everyone.

Mr. Chairman, I noted in your announcement of these hearings that you are interested in whether the tax provisions work as they were intended. On that point, I believe it is worth mentioning that it appears that when Congress enacted the windfall profit tax, it expected the receipts from this tax to increase regularly over time. That expectation was undoubtedly founded on the belief that the price of oil would continue to rise on a relatively straight path.

That, of course, has not happened. The price of oil has fallen steadily since decontrol commenced early in 1981. Not only have WPT receipts tapered off, but the revenues and cashflow of oil and gas producers have been affected.

Some 18 leading companies reinvest about 63 percent of their oil and gas-producing revenues in exploring and developing oil and gas. In 1981, these companies paid out about $14.7 billion in WPT. If those revenues had been retained by these companies, some $9 billion—or 63 percent—would have been spent on additional exploration and development.

Our studies indicate that for every dollar spent, the major integrated companies find about 0.12 barrels of oil reserves—including gas reserves in oil equivalent. That means that some 105 million barrels would have been found in 1981 and added to the industry's reserve base if revenues had not been channeled into the WPT.

This measure of the effect of the WPT on U.S. oil supplies is important to realize in any consideration of tax policy.

Thank you very much, Mr. Chairman.

[The prepared statement follows:]

## STATEMENT OF DILLARD P. SPRIGGS, PRESIDENT, PETROLEUM ANALYSIS, LTD.

### TAX TREATMENT OF OIL AND GAS PRODUCERS

Mr. Chairman, I appreciate your invitation to appear before this committee and to discuss with you the subject of whether differentiated tax treatment between different types of oil and gas producers is good tax and energy policy.

My name is Dillard P. Spriggs. For the past five years I have headed an economic consulting firm in New York called Petroleum Analysis, Limited which I formed in 1978 and which publishes a newsletter called International Petroleum Finance. Previously, I had been Executive Vice President of Baker Weeks & Co., a member firm of the New York Stock Exchange, working mainly in the oil industry from 1958 to 1978. Prior to that experience, I had been associated with W.J. Levy, Inc., a leading oil consulting firm, for eight years. I am also the past President (1981) of the National Association of Petroleum Investment Analysts, made up of more than 500 members from financial institutions.

Let me start by saying that I believe the subject of these hearings, — namely, tax policy -- should be viewed in the context of the overall interest of the United States and its appropriate energy policy. That policy, in general terms, should be to encourage the development of all energy fuels. Oil and natural gas have long constituted the largest share of U.S. energy consumption and supplies. Today, they make up over 60 percent of total U.S. energy consumption.

Because of this high importance, it is obvious that any government policies, in the tax area or any other realm of public policy, have important implications for U.S. energy supplies. In this connection, it is important to note certain recent events in the U.S. oil economy which are affecting significantly the supply situation in the oil industry. These developments include:

- A sharp decline in drilling activity that has seen the number of employed drilling rigs reduced from around 4,500 near the end of 1982 to about 1,800 today. It is likely that the number of wells drilled will fall to less than 65,000 this year from 86,000 in 1982.
- This reduction and the fact that no important new oil fields of size are going to be placed in production either this year or next means that U.S. crude oil production will fall about 100,000 - 150,000 barrels per day in 1983.
- As a result of these developments, the progress that the U.S. petroleum industry has made in recent years in reducing imports of foreign crude oil and refined products will come to an end in 1983. Not only will it end; that progress will be reversed. Imports, excluding purchases for the Strategic Petroleum Reserve, will increase this year by an estimated 500,000 barrels per day.
- This estimate, I may add, is based on a limited increase in U.S. oil demand in 1983 over 1982 of only 1 percent. (See Table I) If the increase should be larger than that due to a stronger economic recovery than now foreseen, or for any other reason, the requirement for imports will increase further.

## TABLE I

## U.S. OIL DEMAND AND SUPPLY
(Thousand Barrels Per Day)

| | Preliminary 1982 | Forecast 1983 |
|---|---|---|
| Domestic Demand | | |
| Gasoline | 6,525 | 6,570 |
| Aviation Fuels | 1,030 | 1,050 |
| Distillate Fuel Oil | 2,670 | 2,610 |
| Residual Fuel Oil | 1,690 | 1,710 |
| LPG | 1,535 | 1,560 |
| Other Products | 2,080 | 2,200 |
| Adjustments | -310 | -300 |
| | 15,220 | 15,400 |
| Exports | 810 | 790 |
| Total Demand | 16,030 | 16,190 |
| Stock Change | -320 | - |
| Total Supply | 15,710 | 16,190 |
| Domestic Production | 10,205 | 10,085 |
| Crude Oil | 8,655 | 8,535 |
| NGL | 1,550 | 1,550 |
| Imports | 4,865 | 5,490 |
| Crude Oil | 3,295 | 3,600 |
| Products | 1,570 | 1,890 |
| Other Supply | 640 | 615 |

## New Phase of Import Growth

I conclude from developments now underway that the United States is entering a new phase in the evolution of its oil economy. It will be one in which its own production of oil will continue to fall off -- probably moderately between now and 1985. Then, in the rest of the 1980's, the rate of decline will accelerate rapidly unless the exploratory effort between now and then is increased substantially and is uncommonly successful in adding new reserves quickly. Output from the Prudhoe Bay field on the North Slope of Alaska, now 1.5 million barrels per day or 18 percent of U.S. crude oil production, will fall after 1986 at a relatively rapid pace and will be difficult to replace.

This means that imports from overseas will be growing at a substantial rate during the remainder of the decade.

The conclusion that is logical to draw from this situation is that U.S. energy policy should be directed toward measures -- both in the tax realm and elsewhere — that help to counteract the future increases in the use of foreign oil.

## The Windfall Profits Tax

Now, let me turn to the Windfall Profits Tax. I believe it has been true since this measure was enacted — and is even more true as we face the rest of the 1980's -- that exploration for new oil should be encouraged. For purposes of both tax and energy policy, that means that there should be no WPT on new oil production.

As one examines the history of oil industry developments which led up to the enactment of the Windfall Profits Tax, I believe that WPT was the

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price that the oil industry had to pay to get out from under price controls. As a result of the increase in the world oil price in the years after the imposition of controls, the removal of control regulations represented windfall gains on oil found and developed 10 years or more earlier.

However, the decline rate in oil and gas production is relatively rapid, making it necessary to phase out the WPT. This Congress did, although one can argue that the phase-out period was extended too long into the late 1980's.

Unlike old oil no windfall gain is possible on newly discovered oil reserves. Moreover, today's economics for finding and developing new oil are relatively costly. And, the price of crude oil has been falling. For this reason, not to mention the deteriorating domestic supply situation that is likely to characterize the rest of the 1980's, I believe that the WPT on new production is a misplaced measure.

It is, of course, true that the Economic Recovery Tax Act of 1981 reduced the rate of WPT on newly discovered oil from the 1981 rate of 30 percent downward in stages to 15 percent in 1986 and thereafter. However, in my opinion, it should have been removed completely.

## Tax Differentiation Between Producers

As to the issue of differentiation in the tax treatment of integrated and non-integrated producers, there is one overriding consideration which indicates that non-uniform application of taxes should be minimized. In terms of the national interest and the need for increasing domestic oil and gas supplies, all barrels of oil and all Mcf's of natural gas are required whoever produces them. Any unit produced adds to supply.

Therefore, there is no need to impose different rates of tax on producers. Rates or exemptions, in general, should be uniform.

I believe that the law regarding expensing of intangible drilling costs (IDC) should be common to all producers. Non-integrated companies may now expense 100 percent of their IDC's. Integrated companies are limited to expensing 85 percent of their IDC's, and write off the remaining 15 percent over 36 months. There is no fundamental reason for this differentiation.

In this connection, it is useful to examine the record of exploration success and new reserve additions in the United States by the major integrated oil companies and by the rest of the industry. Over the four-year period 1978-1981, nineteen of the major companies accounted for over

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TABLE II

Reserve Additions of 19 Integrated Companies
Compared With Industry Reserve Additions

| | 1978 | 1979 | 1980 | 1981 | 4 Year Average |
|---|---|---|---|---|---|
| Additions to Oil & NGL Reserves | | | Million Barrels | | |
| 19 Integrated Companies | 723 | 538 | 1,032 | 1,030 | 831 |
| U.S. Total | 827 | 1,191 | 1,449 | 1,925 | 1,348 |
| 19 Companies as % of U.S. | 87.4 | 45.2 | 71.2 | 53.5 | 61.6 |
| Additions to Natural Gas Reserves | | | Billion Cubic Feet | | |
| 19 Integrated Companies | 5,982 | 5,446 | 5,334 | 5,959 | 5,683 |
| U.S. Total | 18,021 | 14,704 | 14,473 | 17,220 | 16,105 |
| 19 Companies as % of U.S. | 33.2 | 37.0 | 36.9 | 34.6 | 35.3 |

Reserve additions include new discoveries, extensions and improved recovery. The 19 integrated companies include Amerada Hess, Atlantic Richfield, Cities Service, Conoco, Exxon, Getty, Gulf, Marathon, Mobil, Pennzoil, Phillips, Shell, Standard Oil of California, Standard Oil (Indiana), Standard Oil (Ohio), Sun, Tenneco, Texaco and Union.

60 percent of the reserves of crude oil and natural gas liquids found in the United States. Over the same period, these same companies found 37 percent of the natural gas found. The remainder was found by a very large array of companies, most of which were non-integrated companies.

Data show that while finding rates differ among companies and groups, it takes all participants in the industry to explore for and discover oil and gas in the United States. There is no good reason to apply different rates of exemption on IDC expensing to the type of company that takes on the job of exploring for oil or gas. This is particularly true in light of the fact that new reserve additions by the entire industry are not replacing annual production as these figures show:

| | Additions to Crude Oil & NGL Reserves From Discoveries And Extensions | Crude Oil & NGL Production |
|---|---|---|
| | (Million Barrels) | |
| 1978 | 827 | 3,770 |
| 1979 | 1,191 | 3,715 |
| 1980 | 1,449 | 3,728 |
| 1981 | 1,925 | 3,734 |

Additions increased substantially in 1981, the latest year for which data are available, but they still fell 1.8 billion barrels short of production. Even when revisions of prior years' estimates of reserve additions are added to new discoveries and extensions, new reserve additions fall short of production. These revisions were as follows:

| | |
|---|---|
| 1978 | 1,390 million barrels |
| 1979 | 388 million barrels |
| 1980 | 1,993 million barrels |
| 1981 | 1,357 million barrels |

The shortfall reflects the fact that new oil resources are difficult to find and that the search for them requires very large expenditures. The experience of the last several years reveals that the cost of finding and developing oil and gas reserves has increased very sharply. For twenty of the leading U.S. oil companies shown in Table III, finding and development costs increased as much as 2.65 times between 1978 and 1982, reaching $13.84 per barrel last year.

TABLE III

FINDING AND DEVELOPMENT COSTS PER BARREL OF RESERVES ADDED OF TWENTY LEADING COMPANIES
($ Per COE Barrel)

| | 1978 | 1979 | 1980 | 1981 | 1982 | 5 Year Average |
|---|---|---|---|---|---|---|
| Amerada Hess | 10.18 | 36.00 | 32.00 | 6.27 | 16.22 | 11.38 |
| Atlantic Richfield | 4.27 | 9.72 | 11.71 | 10.36 | 18.18 | 10.58 |
| Cities Service | 5.09 | 6.37 | 13.31 | 22.58 | 18.93 | 11.29 |
| Conoco | 6.68 | 7.34 | 5.88 | 14.98 | 16.33 | 9.53 |
| Exxon | 10.70 | 9.66 | 10.20 | 7.81 | 15.44 | 10.50 |
| Getty | 16.54 | 15.97 | 11.73 | 17.80 | 19.57 | 16.18 |
| Gulf | 5.31 | 9.43 | 11.70 | 17.94 | 13.48 | 10.79 |
| Marathon | 3.31 | 11.67 | 7.25 | 12.43 | 22.28 | 8.94 |
| Mobil | 7.15 | 9.27 | 8.46 | 9.82 | 17.60 | 10.27 |
| Pennzoil | 4.71 | 10.09 | 13.05 | 9.87 | 4.43 | 7.05 |
| Phillips | 3.24 | 7.06 | 11.84 | 14.89 | 10.63 | 9.15 |
| Shell | 4.77 | 4.56 | 4.35 | 9.10 | 7.26 | 5.90 |
| Standard Oil of California | 4.00 | 6.50 | 12.26 | 13.71 | 17.76 | 10.31 |
| Standard (Indiana) | 5.59 | 6.87 | 9.21 | 12.92 | 11.61 | 9.29 |
| Standard (Ohio) | 31.17 | 25.38 | 12.04 | 31.79 | 57.85 | 29.92 |
| Sun | 3.25 | 8.07 | 9.78 | 8.39 | 10.52 | 7.94 |
| Superior | 3.96 | 6.58 | 6.76 | 10.06 | 12.43 | 7.98 |
| Tenneco | 2.73 | 4.17 | 6.23 | 8.61 | 11.22 | 6.52 |
| Texaco | 4.59 | 9.55 | 5.57 | 17.69 | 16.50 | 9.47 |
| Union | 2.88 | 4.29 | 6.86 | 9.89 | 11.26 | 6.42 |
| Total | 5.22 | 7.47 | 8.36 | 11.46 | 13.84 | 9.38 |

COE - crude oil equivalent with gas converted to oil.
Finding costs include all exploration costs, capitalized and expensed.
Reserve additions based on discoveries, extensions and improved recovery.

Oil finding costs at the moment are declining, mainly because of the great oversupply of drilling rigs which has resulted in reduced contract drilling rates. It may be that finding and development costs will tend to stabilize for this reason but that will depend on discovery rates of new oil and gas reserves. And as just indicated, discovery of new reserves is difficult. The industry will not add as much to reserves as it did when drilling activity was at high levels. Furthermore, the exploration effort is moving into frontier areas in Alaska and the Outer Continental Shelf where costs are a multiple of those in customary onshore areas. The first well to be drilled in lands obtained in the Beaufort Sea in Alaska during last fall's lease sale will cost around $100 million. Therefore, any stabilization of costs will represent only a temporary respite from the advance.

In short, capital formation in the oil industry is no easy task, and it may pose serious problems for oil and gas producers as they move into the high-cost frontier areas. This is a further reason for not differentiating in the tax treatment of integrated and non-integrated companies.

## Stripper Wells and WPT

Under current legislation, stripper wells owned and produced by non-integrated companies are exempt from the WPT. I believe that this exemption should also be applied to integrated companies for the same reasons I have already cited, namely, that producers of the same oil under the same circumstances should be subject to uniform taxation applied commonly to everyone.

## Conclusion

Mr. Chairman, I noted in your announcement of these hearings that you are interested in whether the tax provisions work as they were intended. On that point, I believe it is worth mentioning that it appears that when Congress enacted the Windfall Profits Tax it expected the receipts from this tax to increase regularly over time. That expectation was undoubtedly founded on the belief that the price of oil would continue to rise on a relatively straight path.

That, of course, has not happened. The price of oil has fallen steadily since decontrol commenced early in 1981. Not only have WPT receipts tapered off but the revenues and cash flow of oil and gas producers have been affected.

Eighteen leading companies (the same companies referred to in Table II with the exception of Conoco for which data are incomplete) reinvest about 63 percent of their oil and gas producing revenues in exploring and developing oil and gas. In 1981, these companies paid out about $14.7 billion in WPT. If those revenues had been retained by these companies, some $9 billion -- or 63 percent -- would have been spent on additional exploration and development.

Our studies indicate that for every dollar spent the major integrated companies find about 0.12 barrels of oil reserves (including gas reserves in oil equivalent). That means that some 105 million barrels would have been found in 1981 and added to the industry's reserve base if revenues had not been channeled into the WPT.

This measure of the effect of the WPT on U.S. oil supplies is important to realize in any consideration of tax policy.

Mr. **Anthony**. Thank you.
Mr. Hickman?

## STATEMENT OF FREDERIC W. HICKMAN, SENIOR PARTNER, HOPKINS & SUTTER, CHICAGO, ILL.

Mr. **Hickman**. Mr. Chairman, my principal claim to expertise here today is that I was present at the creation of most of these differentials. All of them grew, one way or another, out of the legislation designed to deal with the oil crisis, which hit us almost exactly 10 years ago this month.

They have to do, the principal ones, with percentage depletion, and with the windfall profit tax.

As the time all of this began to be prominent, I was the Assistant Secretary of the Treasury for Tax Policy. And I sat with this committee for months on end, and with the Finance Committee after that, dealing with the problems.

Congress has been struggling with it ever since.

My formal statement traces these events, as I think it is important you should know how these things came about, in order to deal intelligently with them now. I won't repeat that except to say in summary that three successive Treasury Departments, under three successive Presidents—Presidents Nixon, Ford, and Carter—told the Congress that these differentials were a bad idea and should not be enacted. Congress ignored the advice. So we have them.

The economic reasons for those positions are well stated by the other witnesses who have appeared here. They were all reasons that the professional economists within these three separate administrations pretty much agreed on. As one of the witnesses a moment ago said, he thought economists were generally agreed.

But having said that we should not have done it, the next thing that I have to say to you is that not doing it is a very much different thing from undoing it. Having done it, what happens is that the markets adjust to what has been done; people make new plans, new commitments, new investments, based on the rulings you have enacted. And if you then pull the rug out from under them by changing the rules, you create all kinds of new hardships.

So, the tax changes, once enacted, get built into the values and the purchase prices, and plans and commitments are made on those numbers.

An asset that produces income with a tax benefit is worth more than a similar asset that produces income without a tax benefit.

If a purchaser buys an asset that has a tax benefit with respect to its income, he will pay for the tax benefit in the purchase price. He will have no special privilege when he is through; there will be no inequity running in his favor. He has bought and paid for whatever benefit is there.

If the purchase is designed to give him a fair return, if he has paid a price that he thinks will produce that result, and then the benefit is taken away, he will have an inadequate return.

So, if you now change all these rules, you will create major hardships for anyone who relied on what you did. And that includes, in the first place, purchasers, but it also includes people who were original owners. Many of them will have borrowed on the basis of capital values and income streams that were projected after tax on the basis of the rules that were enacted. And if those are changed, those owners may find themselves in deep trouble.

You have heard better than an hour's worth of testimony from the Oklahoma delegation about the status of economic affairs there, which is, in substantial part, due to the drop in the price of oil that has occurred worldwide.

My own calculations indicate that if you were to take away from the independent producers the tax differentials that they now have, the result would be equivalent to a price change somewhere in the range of $6 to $12 a barrel. My own guess would be around $10.

If we have had the kinds of dislocation that we have had on a drop of a few dollars from the mid-thirties to roughly $30 a barrel, you can imagine what kind of dislocations we would have, what further bankruptcies and disruptions, with a drop of that magnitude.

So, there are three general economic thoughts that I think are useful lessons to be drawn from this whole history.

The first point is that you cannot assume safely that these differentials produce an inequity with respect to the people in whose favor they seem to run. That is repeatedly the kind of wrong thinking that gets us bad results.

When we are dealing with investment assets, people make calculations and investments on the basis of after-tax returns, and the returns will normally even out in the marketplace, and once that has happened, the fact that there is a benefit attached to some particular kind of asset will not mean that the person owning that asset has a favorable situation. On the contrary, he will normally have a normal return.

So, the first point is, don't assume that the preferences produce a personal inequity running in favor of the people who seem to have it.

The second point is that when you set up differential provisions with respect to assets, depending upon who owns them, the main thing that you do is simply to reshuffle ownership. That is what some of the witnesses were talking about when they said this kind of differential will simply push the industry progressively into ownership by smaller groups which could use the tax differentials, and away from the ownership by larger entities. That won't happen overnight; it won't happen entirely. But the pressure will be on increasingly. That, of course, would argue one should do away with the differentials. But I am not arguing either way on that score. I am just pointing out that that is a consequence of this kind of differential that the committees need constantly to keep in mind, and that they frequently overlook.

The most dramatic example of that consequence in recent years, it seems to me, is in another area. There have been a lot of congressional complaints, and a lot of complaints in the State legislatures about "condomania," the conversion of apartment houses from rental units into condominiums. That is preponderantly the result of the same kind of tax differential we are looking at here.

An apartment in the hands of a rental landlord produces income that is subject to tax. The same apartment in the hands of an owner-occupant produces income in the form of the right to live there, which is not subject to tax. The result is that the condominium—the apartment—is worth a great deal more in the hands of an owner-occupant than in the hands of a rental landlord.

And the moment that the State legislatures passed laws that removed previously existing obstacles, financial and legal, to tenants buying their own apartments, what we saw was a mass migration of the ownership from the hands of those in whom it was worth less—landlords—to the hands of those to whom it was worth more—occupants.

The same kind of things goes on here. It is a subject of concern. But it should have been a subject of concern 10 years ago.

The third and final point I would like to make is that in this kind of area, the principal inequity, if one is looking at inequities, comes from changing things. Because the market does adjust to these differences, the returns to individuals will even out. Then if you make a change, because you think you have something that is more perfect or elegant or desirable in its design, the market has to readjust all over again, and in that process all kinds of people who had normal returns previously will have windfall gains and windfall losses. Thus the change, itself, is a costly, disruptive thing. And it should be minimized.

Now that does not mean you should never make change. But it does mean you need to step up to each individual situation and say, is it really worth doing?

I suggest to you that probably in this case—and that seems to be the attitude, as I detect it, of the Treasury and of the CBO this morning—this change is not worth the candle.

Thank you.

[The prepared statement follows:]

### STATEMENT OF FREDERIC W. HICKMAN, PARTNER, HOPKINS & SUTTER, CHICAGO

I appear today at the invitation of the Subcommittee, not on behalf of any client. The views expressed are my own.

The Subcommittee has requested my comments with respect to Internal Revenue Code provisions which provide different treatment for various types of oil and gas producers in connection with the windfall profit tax and the income tax deductions and percentage depletion and intangible drilling costs.

All of the Code provisions at issue grew out of the energy problems that exploded almost exactly 10 years ago, in the Spring of 1973. At that time, I was Assistant Secretary of the Treasury for Tax Policy, and for the following two and a half years, I met with this Committee and with the Senate Finance Committee for days on end.

All of the provisions under review are part of a larger picture, with other moving parts, and in order to determine whether to change them, you need to recall how they came to be enacted.

At the beginning of 1973 oil was selling at $3 a barrel. Prices had been stable at $2 to $3 per barrel for a number of years. In the United States there was thought to be an economic problem with oil, but it was a problem of over-production and depressed prices. The Texas Railroad Commission rationed oil production in order to prop up the price of domestic oil. The tax treatment of percentage depletion and intangible drilling costs lowered the costs of U.S. producers, thus enabling them to compete better with Middle Eastern oil. An oil import quota kept U.S. prices up by restricting competition from foreign producers.

In 1973, worldwide economic expansion caused oil demand finally to catch up with oil production capacity. In the Spring of 1973, foreign prices began to rise, not much at first. In the fall of 1973, the Arab-Israeli war led to an embargo on middle eastern oil exports and, more importantly, led to tight cooperation among the OPEC countries in restricting oil production. Prices increased radically in late 1973, rising to $10 by early 1974.

Meanwhile, the general price control program imposed in 1971 was being gradually phased out. But the dramatically escalating price of oil made it politically impossible to decontrol oil.

Congress geared up to deal with the oil problem and the differentials between large and small producers had their source in the legislation which followed.

The Nixon administration, with George Shultz as its chief economic spokesman, believed that, in the end, the only workable solution to the oil problem was to permit market forces to operate freely. Higher prices would result from decontrol and would bring supply and demand into balance. Higher prices would call forth increased drilling and a larger supply of oil and would, at the same time, dampen the demand for oil. The Carter administration subsequently took much the same position. Time has proved the position correct, but in 1973 it was very controversial and politically unpopular.

The immediate problem in 1973 was that corrective market forces were bottled up by the 1971 price control program. There was, of course, no way to control the price of foreign oil, and those U.S. companies with extensive foreign production reported sharply higher profits on foreign sales. Although foreign governments quickly found ways to siphon off those profits, there was a public perception of oil company profiteering, fanned by political demagoguery and by the normal unhappiness of consumers with higher prices. In ordinary times, the market price changes would have come swiftly and would have been a *fait accompli*, to which the public would have adjusted, before the political machinery could be cranked up to stop it. But that could not occur with price controls still in effect.

To deal with the problem, both economically and politically, the Administration proposed, in late 1973, a so-called windfall profits tax. The tax was intended to assuage the public perception of profiteering and to create a political climate which would permit decontrol and a return to a competitive marketplace. The key concept underlying the windfall profits tax was that oil production responds to oil price changes only after substantial time lags. Given the nature of exploration and development, it takes three years or more before a substantial increase in prices results in a substantial increase in production. Thus the level of production during 1973 and during the next several years would be the result of commitments made when oil was $3 a barrel and would be relatively unaffected by the fact that the price had risen from $3 to $10. The $7 increase in price, during the lag period before it produced an increase in production, constituted what economists technically refer to as a "windfall" or as "economic rent." The proposed tax was carefully constructed to self-destruct gradually, so that producers could make commitments for new production that would pay off with a $10 price and the assurance that the tax would not take most of the $10 away. In technical terms, the aim was to have the tax gone when the technical "windfall" was gone.

A question which arose early in our technical sessions at the Treasury was what positions should be taken with respect to percentage depletion. The elimination of percentage depletion was sure to be raised as an issue in this Committee and in the Finance Committee regardless of what proposals were advanced by the Administration.

A number of individuals argued that percentage depletion could no longer be justified and should be eliminated. They argued that:

1. The deduction for percentage depletion (as distinguished from cost depletion) had no legitimate role in measuring income. It crept into the early income tax law based on primitive notions of income definintion, long since abandoned by most economists. It could be justified only as an incentive preference.

2. Events had superseded the traditional argument that percentage depletion was needed as a production incentive. In an era of $3 oil, percentage depletion and provided, at most, about 40¢ of after tax incentive to a 50% taxpayer. The $7 increase in the pride of oil from $3 to $10, on the other hand, would produce more than $3.50 of additional after tax incentive.

3. The price rise also meant that there would be no hardship in eliminating percentage depletion. As percentage depletion had existed for many years, its value had been capitalized in the price of producing properties.

Owners who had bought properties from others would have paid for depletion in the price of the property. For them, depletion produced no extraordinary benefit and, under ordinary circumstances, taking it away would deprive them of a fair return, However, in 1974, taking it away, would produce no hardship, as the increase in oil prices would make up several times over for the loss of depletion. Thus, if depletion were ever to be eliminated, it was argued, 1974 presented a once in a lifetime opportunity to do so without hurting anyone.

4. The elimination of depletion, it was argued, ought to be supported by all persons who believed in free markets. Percentage depletion is an anti-free market provision because its result is to discount by 22% or more the tax rate applicable to income from oil production, compared with other enterprises. By doing so, it tilts marketplace decisions, causing the public to make choices which it would not otherwise make.

Proponents of retaining percentage depletion argued, to the contrary, that:

1. Any attempt to eliminate percentage depletion would—regardless of the merits from an economist's point of view—engender intense political opposition which would jeopardize enactment of the overall program. The most important thing was to get oil decontrolled as quickly as possible and to restore free market conditions for energy generally. Compared to that major goal, percentage depletion was a minor item. While free market advocates ought, theoretically, to approve the elimination of depletion, the fact was that most of those directly affected would not. Furthermore, since percentage depletion also applied to so-called hard minerals, where prices had not risen and elimination would be a hardship, any proposal to eliminate it would arouse strong opposition from other quarters.

2. Regardless of the fact that the $7 price increase provided a powerful production incentive, the urgent need for more domestic production justified all the incentive available. If percentage depletion produced a "misallocation" of resources, it was the very kind of misallocation which the country needed, i.e., more drilling.

3. Any inequities or misallocations thought to exist in connection with percentage depletion were adequately handled by the comprehensive package of general "tax reform" proposals, unrelated to the energy, which the Administration had put forth earlier in 1973. That package contained provisions which curtailed the deductions for both percentage depletion and intangible drilling costs.

You will observe from this recitation of arguments that whether or not to propose the elimination of depletion was a political decision which transcended questions of tax policy. It was ultimately decided at the White House, after input from other departments, to support the retention of percentage depletion. I was instructed to communicate that position when questioned by the tax writing committees.

At this same time it had become clear that there would be political moves of small producers to disassociate their treatment from that of larger producers. It was apparent that they would ask for exemption from the windfall profits tax or, at least, for preferential treatment. And if depletion were repealed, notwithstanding the Administration's views, they would want exemption from that repeal.

I knew I would be asked for the Adminstration's position on that subject. That, too, was referred to the Secretary for White House decision. I was in due course instructed to take the position that whatever tax provisions were ultimately enacted or repealed, they should apply equally to all production, regardless of the taxpayer entity in which production occurred. That conclusion was based on the belief that different rules for different kinds of producing entities would create all kinds of marketplace distortions within the oil industry itself, as resources were shifted in or out of particular entities, or locked in place where the tax effect would be most favorable, that major inefficiencies would result, and that setting one class of producers against another class of producers was likely to produce the same kind of politico-economic quagmire produced by the entitlements rules.

In the months that followed, Congress elected not to deal with the windfall profits tax proposal, nor to decontrol. But it did proceed, in the 1975 tax reform legislation, to deal with the subject of percentage depletion. There were vigorous debates in this Committee on whether to repeal percentage depletion for oil and, as expected, there were proposals to repeal it for large producers, but leave it for small producers. As instructed, I repeatedly asserted the Treasury's opposition to any such double standard.

Ultimately, this Committee reported a bill which would eliminate percentage depletion for everyone, but would do so only gradually for small producers. When the bill got to the Senate there was again a strong push to exempt small producers from the provisions (and to expand the definition of small producer). Again, I asserted the Treasury's view that depletion should not be repealed, but that if it were repealed it should be repealed uniformly for all taxpayers. Again, both positions were rejected. The Senate went even further than the House and repealed percentage depletion generally but retained it permanently for certain classes of small producers. In conference the Senate position was adopted. In preparation for this testimony, I re-examined the legislative history and was reminded again of the wide Congressional support given to the differential treatment by members from both ends of the political spectrum, including by many self-proclaimed tax reformers.

The question of oil price decontrol and windfall profits taxes continued in legislative turmoil for several more years. Finally, in 1980, the Carter Administration supported and Congress enacted a so-called windfall profits tax, coupled with the decontrol of domestic oil prices. The windfall profit tax, while it retained the label of the 1974 proposal, was in economic effect significantly different, insofar as it was not confined to the windfall element and was not designed to disappear as the windfall disappears. The new Windfall Profit Tax incorporated the same kinds of distinctions between large and small producers that had been incorporated in the 1975 provisions repealing percentage depletion. The Carter Treasury, like the Nixon-Ford Treasury which preceded it, also unsuccessfully opposed those distinctions.

Thus, we have today a system of taxing oil production which injects significant anti-competitive elements into the economics of the industry. Oil is worth more in the hands of some producers than in the hands of others. That gives a quasi-monopoly advantage to certain classes of producers and erects barriers to others. The free purchases and sale of oil properties is obstructed. Constant tax planning and legal vigilance is required to ensure that maximum tax benefits are realized or preserved. In some cases, businesses are pressured to restructure in response to such rules as the rule that imposes a heavier windfall profit tax on producers that also own refineries—a downright silly rule which was apparently motivated by vindictiveness, not economics.

In short, whatever the merits of repealing percentage depletion and imposing a windfall profits tax may have been, the nonuniformity of those provisions is most unfortunate. The differentials between producing entities should never have been enacted.

But having said that, I hasten to say, in my very next breath, that whether those differentials should have been enacted in the first place is an entirely different question from whether they should now be repealed. The fact is that the provisions, once enacted, become the basis for taxpayer plans and commitments. The benefits of the differentials have been capitalized in higher values for the properties affected. The well that produces oil eligible for percentage depletion and for preferential treatment under the windfall profits tax is worth more than a well which doesn't. A subsequent purchaser of the favored well will, in effect, pay the original owner for the value of the tax benefits that can be transferred. In the marketplace, buyers look at the projected after-tax income streams and pay a price such that the income stream provides a fair and reasonable return. If the income stream is thereafter reduced, the buyer will have paid too much, and will be reduced from a fair return to an inadequate return. Such a buyer has no special preference under the present differentials and an adverse change in the differentials could be financially disastrous to him.

The hardship is not confined to subsequent buyers. A big jump in the tax burden may be equally disastrous even if the property is in the hands of an original owner who never paid for the benefits. Even if one concludes philosophically that the differentials should never have been enacted, there will be all kinds of practical problems if the owner's after tax income stream diminishes significantly and the value of his properties plumments overnight. He may, for example, have borrowed heavily against the current income stream and the current value of the property, and a sudden drop in the value and income stream could leave him in bankruptcy. The recent drop in oil prices has had exactly that effect on many oil producers throughout the country. At $30 a barrel, repealing percentage depletion for all producers and subjecting all producers to windfall profits tax uniformly at the highest rates could reduce the after-tax cash flow by as much as $3 to $4 a barrel. That after-tax reduction would be equivalent to a drop in the price of oil (the price being a pre-tax figure) of 2 to 3 times as much—i.e., $6 to 12. (Precise numerical comparisons are not possible because a variety of assumptions and variables are involved.)

There are several generalizations that I should like to make in concluding:

1. One cannot assume that the existence of a tax differential in favor of a particular class of taxpayer investor necessarily produces an unfairly high return for that class. Whenever assets are bought and sold, many owners will have already paid someone else (in the purchase price) for the benefit. Taking the benefit away will leave them not with a normal return but with an inadequate return.

In the case of investment assets, once the marketplace has adjusted to tax differentials, they rarely produce inequities. What differentials do produce is a reallocation of the kinds of assets held in the economy and a reshuffling of who owns them.

While this generalization is a fairly elementary ecomomic principle, it is not well understood by the public. Obviously that makes it difficult to legislate good tax laws. I regret to say that the principle seems not always to be understood by the tax writing committees, either—or at least if they understand it they often choose to ignore it.

The differentials at issue have clearly created market distortions and resource misallocations which could have been avoided by not enacting the differentials in the first place. But once enacted it is not possible to unscramble them without hurting people. These hearings should have been held 10 years ago rather than today.

2. Another economic principle, related to the first, is that where transferable assets are involved, tax differentials based upon the entity which happens to own the assets (as distinguished from differentials based upon the assets themselves) will principally result in a reshuffling of ownership interests. That may, in turn, create new problems.

If it is more profitable for X to hold an asset than for Y to hold it, the asset will in time come to be held by X. If it is worth more to X than to Y, X will be willing to pay Y a price at which it is attractive to Y to sell.

The most dramatic example of this principle in recent years has been in connection with condominium apartments. In the hands of a rental landlord, the apartment produces income that is taxable. In the hands of an owner-occupant, however, the "income" from the apartment, i.e., the value of living in it, is not taxable. Accordingly, the apartment is worth much more to an owner-occupant than to a rental landlord. For many years there were legal and financing obstacles to tenants buying the apartments. When those barriers were removed by condominium legislation, what followed was a mass migration of apartment ownership from rental landlords to owner-occupants. Apartments were simply worth more in the hands of owner-occupants, who then were willing to pay rental landlords more than the apartments were worth to them. Although there were contributing factors, "condomania," as it came to be called, was primarily a tax phenomenon created by differentials in the tax treatments of the same assets in the hands of different owners.

The tax differentials under review here have a similar effect. They tend to push the ownership of producing properties into the hands of tax-favored owners. That is both anti-competitive and economically inefficient. At a time when we are trying to get all of the production we can from as many different producers as we can, it is counterproductive. But this too, is something that should have been taken more seriously 10 years ago.

3. An old tax is generally the best tax, even if less perfect than a new tax. This is an old maxim of economists, neglected for the last two decades. The marketplace will adjust to any tax, and will tend to even out returns and inequities. Once that occurs, the enactment of any new tax that replaces it—no matter how much more rational in design—will create new inequities, new windfall gains and losses, as the marketplace readjusts from the status quo. At least in so far as taxation of income from capital is concerned, it is change which creates the most inequity, as well as the most disruption.

The inequities caused by change may, of course, be outweighed by the need to correct misallocation or distortions, but one should carefully consider whether that is so in any particular case.

If you seek now to eliminate the differentials that you deliberately enacted over the last 10 years, you will learn quickly from your affected constituents that you cannot do so without creating major hardships for many who have relied on what you did. At the very least, you will end up with long phase-in periods, so you should dismiss from your minds the allure of large revenue gains this year or next.

Since 1969, the economy has been in constant turmoil with legislated tax changes. I respectfully suggest that your committee give serious consideration to the proposition that the most useful thing you can do today for the economy is to declare a moratorium on all but the most pressing changes, and give the country a chance to make plans and commitments based on rules that are stable. In the economy as a whole, the price of change and instability is very considerable.

Mr. Anthony. Thank you, Mr. Hickman.

First, maybe we should give you a few additional minutes of rebuttal time, Mr. Spriggs. As I understand the nature of your two testimonies, you track different philosophies when it comes to treating different segments of the industry differently as far as the tax code is concerned.

I understood Mr. Hickman saying regardless of what past administrations have recommended, Congress has done it and ought to leave it alone, and it will be worse if we go back and tinker with it.

Yet, you have forcefully said you thought that the industry would be better off if all segments were taxed the same.

Mr. **Spriggs**. I think we are fairly close. He says leave it alone. I just say put everybody on the same basis by giving the integrated companies what the nonintegrated have.

Mr. **Anthony**. If that happens, who do you think benefits?

Mr. **Spriggs**. I think you would benefit in finding more oil and gas.

The more cash flow you can put into the hands of oil producers, whether they are integrated or not, increases the supply of oil and gas.

Mr. **Anthony**. I guess what I am trying to get to is that if we make them all the same, Mr. Hickman is indicating that there would be some different types of economic and fiscal behavior that would take place as a result of that. And I just wonder——

Mr. **Spriggs**. What he is saying is, if you take away the exemptions that the independents have, you will cause hardship on them, or you will cause difficulty.

Mr. **Anthony**. Do you agree with that?

Mr. **Spriggs**. I would rather put it the other way—to give it to the integrated companies, and you increase the supply of cash flow, and, therefore, you increase the supply of oil and gas.

Mr. **Hickman**. I agree completely with that. I have no difference at all. It just did not occur to me you were conceivably going in the other direction. And I haven't supposed, from the politics of that, that was an alternative. But it does depend on how you do it. If you wish to give up the revenue and let it even out the other way, that is the best of all possible worlds. The initial windfall profit tax that we proposed in 1973 was designed to be gone by now. That was a key feature of its design. And I still think that was sound. That is entirely consistent.

Mr. **Spriggs**. That is what I said in my testimony; that it should have been phased out sooner.

Mr. **Anthony**. I guess it is about 11 years now. After 10 years, it is down a percentage every 3 months?

Mr. **Hickman**. Yes.

Mr. **Anthony**. So, if we changed the premise, Mr. Hickman, you would change your position, and you would agree, then, with Mr. Spriggs that maybe it ought to all be made equal?

Mr. **Hickman**. The best thing that could happen, it seems to me, would be to get rid of the windfall profit tax and put the whole thing back in as freely competitive a marketplace as you could.

Mr. **Anthony**. But what about the other differences in the code that vary between the independents and the integrated companies? Equalize all of those, too?

Mr. **Hickman**. It depends. Some of those are in there for different purposes. I commented on the windfall profit tax and the percentage depletion differences. There are items that relate to the minimum tax. For example, corporations are treated differently——

Mr. **Anthony**. Let me restate it in a more formal manner.

As an industry analyst, when you are advising an investor, do you take into consideration whether the producer is an independent or an integrated company?

Is it more important that the producer is large rather than small? Do you take into consideration the tax benefits available to independent producers, and, if so, which do you think are the most important—the percentage depletion or the lower rates on windfall profits tax? And how do these compare with the ability of all producers to expense IDC's?

Do you take the tax consequences into consideration, whether you are an independent or integrated company?

Mr. HICKMAN. We are always looking at the numbers and the particular situation before us, and those things are all very much affected by whatever the tax rules are. And you frequently try—you almost always try—to structure your transaction so that things end up in the compartment that has the most favorable tax rules—if that is possible within the framework of what the parties want to do.

Mr. ANTHONY. Mr. Spriggs?

Mr. SPRIGGS. Well, when we do it, we look at what we call the bottom line, or the rate of return, and when you are looking at the rate of return, you are going to be affected by the tax rates. That is very obvious.

What we are looking at is not between an independent or an integrated company. We are looking at the projects. You have a project—East Texas, in southern Louisiana, something in California—and you look at the rate of return on that project, and then you factor in the different tax rates.

The tax rates usually don't make that much difference.

Mr. ANTHONY. I think that is where I was going based on what Mr. Glickman said and Mr. Dorgan had said earlier.

My last question is: What impact does the price of oil have on investment decisions?

Mr. SPRIGGS. It has got a very measurable impact. Since last year—well, since early 1981, the price of crude oil in the United States is down from $36 or $38, down to somewhere in the area of $29, $30, maybe $28. The price of oil has a great deal to do with it.

Mr. ANTHONY. Did you have a comment you wanted to make?

Mr. HICKMAN. No; I agree with that. In my testimony I have explained in some degree the dollar comparison between the price of these items and the price of the barrel, itself. The tax benefits, in the extreme case of the independent producer, are worth a lot of dollars per barrel, quite comparable to the kind of price drop we have already had.

Mr. ANTHONY. It was your testimony that you think the average barrel price would change $10 if all the tax rates were equal.

Mr. HICKMAN. It could change as much as $6 to $12. One could not pick a particular price, because there are too many variables and assumptions. But somewhere in that range, you would have to have that kind of a change, and the result of taking the tax benefits away would be equivalent to that kind of a drop in the price of oil.

Mr. ANTHONY. For the independent.

Mr. HICKMAN. Yes.

Mr. **Anthony**. I think that was the whole basis of the original question that I asked. Who benefits and what economic behavior would you anticipate in the industry? I think by your followup answers to other questions, it is obvious that the independents would be in trouble.

Mr. **Hickman**. Yes.

Mr. **Anthony**. I think that is the point we are trying to make. Mr. Thomas?

Mr. **Thomas**. No questions.

Mr. **Anthony**. We thank you very much for your testimony and valuable contribution to the oversight hearings.

Our next witnesses will be a panel of the Independent Petroleum Association of America: Mr. Sid J. Jansma, Jr., vice chairman of the Tax Committee; Lloyd Unsell, executive director; and H. B. Scoggins, Jr., general counsel.

### STATEMENT OF SID J. JANSMA, JR., VICE CHAIRMAN, TAX COMMITTEE, INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA, ACCOMPANIED BY LLOYD UNSELL, EXECUTIVE DIRECTOR; AND H. B. SCOGGINS, JR., GENERAL COUNSEL

Mr. **Jansma**. I would like to make a comment on your previous discussion, regarding whether advantages——

Mr. **Anthony**. Would you identify yourself?

Mr. **Jansma**. Yes, sir; I am Sid Jansma, Jr. I am representing the Independent Petroleum Association of America.

Mr. **Anthony**. Why don't you go ahead and introduce the gentlemen with you?

Mr. **Jansma**. The gentleman on my left is Mr. Lloyd Unsell, executive director of the Independent Petroleum Association of America. And, on my right, Mr. Bud Scoggins, general counsel.

Just to make a comment on your previous discussion, there is a thought going through my head: When we shoot someone in the foot, do we want to shoot someone else in the foot? And I guess regarding the advantages or items that the independents have, we certainly, as independent producers, do not object to according benefits to the majors that accrue to us.

Mr. **Anthony**. You have a prepared statement. It will be accepted in full for the record without any objection.

You are now free to proceed as you desire.

Mr. **Jansma**. Thank you very much.

Again, my name is Sid Jansma, Jr.

The Independent Petroleum Association represents over 8,000 independent explorer producers, and we appreciate your allowing our prepared statement to go in the record.

We have recently received copies of background material prepared by your committee staff. We respectfully request the opportunity later to submit for the record a response to certain questions.

Chairman **Rangel**. Without objection, you will be allowed to do so.

Mr. **Jansma**. Thank you.

It is clearly documented in recent news accounts the domestic petroleum industry is in a very severe depression. While the rest of the economy has been showng signs of improvement the past several months, domestic oil and gas producers have continued a severe decline.

I would like to call your attention to the first of the large charts at the side of the room. It is the chart with the oil derricks on it. This illustrates that for several years we had a rapidly increasing rate of drilling activity leading to a record-breaking year in 1981. As a matter of fact, in December 1981, we had 4,530 drilling rigs active in the United States.

Since that point, the industry has experienced the sharpest decline ever in the drilling rate and rig utilization rates. Last month only 1846 rigs were making holes in the United States. We have stacked 60 percent of our drilling force. Not only are more than 40,000 drilling rig hands unemployed, but at least twice that many people in service industries are unemployed.

Crude oil prices have declined sharply over the last several years. While the average price for domestic oil is now only $26.50 a barrel, the perception persists that producers are still getting $28 to $30 per barrel. That's closer, frankly, to the price which imported oil commands, which is getting a premium above domestic oil.

But whatever the price of a barrel is, by the time the producer gets his part of the wellhead price, the barrel has shrunk considerably.

I would like to direct your attention to the second chart with the word "Oil" on it. The first thing that happens is that 15 percent of the barrel comes right off the top for the royalty owner. That is the landowner, the private royalty owner.

The next item is 7 percent, which is taken out to go to the State and local governments in the form of severance and production taxes. Then comes the windfall profit tax which takes an average 23 percent. This leaves the producer with approximately 55 percent of the barrel for his own use.

The producer has to pay his operating costs, his overhead, all of his other drilling costs, for drilling new wells, has to support his family out of what is left. In addition, he has to pay all of his State and Federal income taxes out of what is left.

Many people seem to believe that producers are either sitting on this revenue or diverting it to other uses. As illustrated by our third chart, the circle, the facts are that independent producers have for the last 10 years been spending $1.08 for every dollar of revenue received from the sale of oil and gas. For your information, this is the most current number that we have received from the Department of Census.

You have heard Senator Boren mention 100 percent reinvested. One of the other members mentioned 105 percent. But actually, 108 percent of the receipts from sale of oil and gas are reinvested in the industry.

Obviously, this can only be possible by using significant amounts of funds from outside investors, and money acquired through borrowing based on existing production. This is a clear illustration of why the present tax incentives are absolutely essential to make possible the investment necessary to maintain our energy security.

Now, except for the portion of these funds which go for Federal taxes, the great majority of expenditures go directly into the local economy to be rolled over throughout the economy generally.

Our fourth poster illustrates this: Steel pipe and tubing, drilling muds and brines, oil field services and supplies such as cement, tools, trucking and hauling services, drilling contractors and drilling rigs, professional services of many types, and a myriad of other supplies and services. Of course, each of these items creates jobs both locally and throughout the economy.

Now, I would like to focus for just a moment on the energy supply needs which our industry must fill. Our last poster shows if we assume an annual growth in oil consumption of only 2 percent over the next decade, and agree that it is sound energy policy to hold imports to no more than the present 30 percent of total consumption, then by the year 1992 we will need 11.4 million barrels of oil per day. To get there from our present rate of about 8.7 million barrels per day, and to make up for the loss which occurs due to normal production declines from existing wells, means that in 1992 we must add almost 8 million barrels per day of new crude oil production.

Mr. PICKLE. I want to get those figures. What page are you on?

Mr. JANSMA. I am reading from a summary of what we presented to you. And I will get—I think we have a summary right here. I will be pleased to give it to you.

Mr. PICKLE. We will get them.

Mr. JANSMA. Each of these statistics is listed in the printed material we have given you. It is on page 5 of the summary.

Mr. PICKLE. I am simply trying to establish how many more wells we will need to drill by when, just to keep up.

Mr. JANSMA. The significant thing about this last chart is that we have to find 8 million barrels of oil per day. But the significant thing is when you relate that to the number of wells that need to be drilled, we will have to drill 890,000 new wells between now and 1992 at an expense of some almost $500 billion.

Now, I would like to make some comments on general tax policy.

Generally, energy tax policy should be designed to extend the economic life of existing energy-producing properties and encourage development of new ones.

Policies intended to accomplish these objectives must take into account certain basic characteristics of oil and gas exploration and development. I would like to list four of them.

Exploration and development of crude oil and natural gas resources are both capital-intensive and have high risk.

No. 2, long lead times before investment generates significant return compounds both the risk and the capital requirements.

No. 3, unlike most industrial enterprises, the successful ventures, that is producing wells, must not only be self-sustaining, but they must also pay for the unsuccessful ventures, dry holes.

To respond to these issues being considered by this subcommittee, we have divided our testimony into five parts. I am just going to summarize each one.

The first part is, the reasons for granting tax incentives for oil and gas producers are as compelling today as when those incentives were first enacted.

As has been said earlier, it was after World War I that Congress fashioned the main tax incentives for the domestic petroleum industry. These incentives were grounded in the sound principle that it was in th best interests of national defense and economic stability to develop our secure indigenous petroleum resources. That reason still exists today.

The second item we would like to address is tax incentives should be evaluated considering the economic impact of increased drilling activity. On March 7 the Congressional Joint Committee on Taxation published its annual estimates of Federal tax expenditures. These figures purport to estimate revenue loss to the Government, but they do not take into account the economic benefits to the Nation of having that purchasing power invested by the private sector.

In the case of oil and gas exploration, the drilling that has resulted from high levels of investment made possible by the tax incentives has had a dramatic payoff, both in macroeconomic terms and in various local economies around the United States.

I would like to just point out this one item. For your information, it is on page 9 of the general comments.

Based on experience of recent years, for each $1 billion spent on finding and developing crude oil and natural gas, an additional 20,000 barrels of daily production of crude oil equivalent can be established during the next 10 years. Mind you, that was a $1 billion investment. Yet, this production will back out $2.9 billion in imports.

In addition to these benefits, on the macroeconomic level, it should be noted that the money spent on increased drilling is injected into the local economy for new jobs, increased taxes, as pointed out on the chart with the arrows.

Our third main division we would like to address is that there is a strong relationship between Government tax policy and the results sought to be achieved.

The close relationship between Government tax and pricing policy and the industry response is demonstrated in research and by historical example. We have cited several things in our prepared testimony. I would like to pass over them now, but I would like to mention just one item.

Oil and gas depletion was singled out in 1969 and was reduced. This action was followed in 1970 and 1971 by the two largest drops in exploratory drilling in the history of our industry, even though in both of those years the price of natural gas and crude oil was going up.

The fourth division we would like to point out is that differences in the tax treatment of various segments of the industry, such as distinctions between integrated and nonintegrated companies are a rational attempt to reflect differences in the characters of these segments.

U.S. tax policy has also been guided by a desire to tax all enterprises in a manner which reflects their unique characteristics. Today we have different tax schemes that have been adopted to account for fundamental differences in the nature of such businesses as public utilities, farmers co-ops, banks, et cetera. These principles likewise influence the taxation of the petroleum industry from the beginning of the income tax.

The earliest revenue acts recognized the unique risks inherent in the exploration process, and provided that all costs incurred in making wells capable of production, but which had no salvage value, could be currently deducted as an expense.

In addition, recognition of depletion has a similar lengthy history. The concept of statutory depletion was adopted as the means to recognize consumption of a physical asset as it is removed and produced.

Percentage depletion is a highly efficient incentive mechanism. The impact of percentage depletion has been widely recognized and percentage depletion is in effect for 105 minerals today, including oil and gas.

All oil men experience losses. Consequently the successes need to provide more than a recovery of capital before the ordinary tax rates apply. Percentage depletion provides this.

The oil man has to cover the costs of his dry holes. For exploratory wells, 80 percent are dry holes.

The option to deduct intangible drilling costs and the recognition of depletion are not the product of congressional favoritism to a special class of taxpayers. These provisions have endured through 70 years of economic change only because they make good sense.

Beginning in 1969, with the reduction of the rate of percentage depletion, these historical incentives have been continually diluted. Subsequent legislation, moreover, almost uniformly recognized the special role and character of independent producers who are neither significant retailers nor refiners.

Historically, independent producers have concentrated their efforts in the petroleum industry's high-risk section, that is exploration and development. And they have always been responsible for the majority of exploratory wells on the continental United States.

As a general rule, the major oil companies have concentrated their exploration efforts in areas considered likely to yield significant discoveries, such as Alaska, offshore and other places. The independent producer, however, has maintained his exploration efforts over a much broader geographical area, and it is from these more modest successes that our domestic production has been maintained.

Energy security will not be the result of a few spectacular discoveries, but will come from the multiplicity of effort of the thousands of independent producers each adding their part to the total.

It was recognition of this vital role of the independents in exploration which resulted in the reduced windfall profit tax rate for independent producers on tier 1 and tier 2 oil. These provisions maximize incentives where they are most needed to stimulate exploration for new production in existing fields and to extend the economic life of marginal or stripper wells.

Continued drilling is required to both fully develope known fields and to establish their limits.

The incentives to stripper well properties have unquestionably had great impact. Since 1973, the number of producing stripper wells has increased from approximately 355,000 to 410,000 in 1981, while for the same period the total producing oil wells in the United States increased from 500,000 to 560,000.

Stripper well properties account for more than ⅛ of the total production of U.S. domestic crude oil. This represents 1.2 million barrels of crude oil daily, and each barrel of stripper oil retained through decreased abandonments is 1 less barrel to import and 1 less barrel of new oil we need to discover.

The fifth and last thing I would like to address is that proposals to change tax incentives add the uncertainty of tax treatment to the already existing uncertainty of price.

The problem in maintaining our Nation's supplies of oil and gas is not one of resources. We have those resources. It is not one of resourcefulness. We have the resourcefulness to tackle difficult technical problems. The real problem facing producers today is one of economics, the availability of capital.

Unlike an integrated oil company, which has opportunities to profit from the refining of oil, the transportation, and the marketing of it, the independent producer can obtain his revenues only from sales at the wellhead of oil and gas. It is these revenues which must provide the capital for continued exploration, yet currently nearly half of the value of a barrel of oil disappears before it reaches the producer, as you can see on chart No. 2.

Because overhead and operating expenses of wells are essentially fixed, every dollar of income diverted to taxes reduces by at least a dollar expenditures for exploration and drilling.

The resources of the independent producer have shrunken drastically in the last 14 months. Just consider in the last 14 months the price of crude oil has gone down 25 percent. In the last 14 months it has become increasingly difficult to sell natural gas. In the last 14 months we have been able to raise about $44 billion less from the private sector of the economy for input into exploration drilling.

All of th[illegible]ve had significant negative impact on drilling in the Unite[illegible]

That [illegible]inted out on the first chart, where you can see the imp[illegible]ng, where the active drilling rigs have fallen from a high [illegible] a low last month of 1,800.

Sound ta[illegible]ould prohibit the levying of additional punitive taxes [illegible] any industry in the crippled state of the petroleum industry today. We must keep in mind the task we have before us.

Just to maintain current levels of domestic production, 570,000 new wells must be drilled through 1991. And that is to just maintain current levels, not to reach the 11.4 million barrels per day we will need by then.

But maintaining our domestic production is not just a matter of increasing the expenditures of our existing producers. We must also increase the number of producers. It is the formation of new companies and the ease of entry for individuals and partnerships into the business that is necessary for sustained growth.

For these new entrants and emerging enterprises the existing tax incentives are both the most necessary and the most beneficial.

The energy future of America literally will be secure or insecure based on the public and political understanding of these two facts—

one is that anyone can get into the oil business today. The second fact is that no one has to stay in it.

With encouragement from you, our Government, we independent explorer-producers will continue to fulfill the same vital role we have filled in making this country one of the world's leading energy producers.

We thank you very much. And we would be delighted to answer any questions.

[The prepared statement follows. See p. 292 for comments subsequently received on testimony presented by others.]

## Statement of Independent Petroleum Association of America and American Association of Petroleum Landmen, Arkoma Basin Independent Gas Producers Association, California Independent Producers Association, Eastern Kansas Oil and Gas Association, Inc., Illinois Oil and Gas Association, Independent Oil and Gas Association of West Virginia, Independent Oil Producers Tri-State, Inc., Independent Petroleum Association of Mountain States, Independent Petroleum Association of New Mexico, Indiana Oil and Gas Association, Kentucky Oil and Gas Association, Liaison Committee of Cooperating Oil and Gas Associations, Louisiana Landowners Association, Inc., Louisiana Association of Independent Producers and Royalty Owners, Michigan Oil and Gas Association, National Stripper Well Association, New York State Oil Producers Association, North Texas Oil and Gas Association, Ohio Oil and Gas Association, Oklahoma Independent Petroleum Association, Panhandle Producers and Royalty Owners Association, Pennsylvania Grade Crude Oil Association, Pennsylvania Oil and Gas Association, Permian Basin Petroleum Association, Royalty Owners and Independent Oil and Gas Producers Association of Arkansas, Tennessee Oil and Gas Association, Texas Independent Producers, and Royalty Owners Association, Virginia Oil and Gas Association, West Central Texas Oil and Gas Association

### EXECUTIVE SUMMARY

As we all know, this country developed and maintained energy supplies in excess of its needs for more than a century. This did not occur because providence favored America over other nations with petroleum deposits. It did not happen because we—as a people—possessed a keener nose for oil and gas than others. It happened because only in America are individuals permitted rights which are the essence of private enterprise—the rights to own, to sell, to buy, to explore and to produce petroleum fuels. In every other nation those rights are reserved by and for governments.

Now, these unique rights existing only in America guarantee nothing to anyone. In the cumulative experiences of tens of thousands of explorers, successes have ranged from object failure to extraordinary discoveries. It has been the possibility of extraordinary success that has lured so many, for so long, to the search for oil and gas. Should that possibility ever be lost or denied, our energy and economic futures will be foredoomed.

The energy future of America literally will be secure or insecure based on public and political understanding of two very simple facts: (1) Nobody is excluded from the oil business, but (2) Nobody has to be in the oil business. With encouragement to help meet this country's future energy needs, independent explorer-producers will continue to fulfill the same vital role they filled in making the world's leading energy producer of a country that could have never realized such achievement under any but a free economic system that rewarded the risks and successes of private enterprise.

The Subcommittee's April 15th press release announcing today's hearings states that the Subcommittee will inquire into whether the present tax treatment of oil and gas producers is good tax and energy policy, and whether the specific provisions providing different tax treatment work as they were intended. IPAA believes that these tax incentives are a vital force in encouraging investment of the unprecedented amounts of capital required over the next decade to develop our domestic energy resources and achieve our economic and energy policy needs. We want to emphasize that a dollar invested in exploration and development of crude oil and natural gas does not result in a dollars worth of oil and gas being produced over the past decade for example, the $116.8 billion spent by independent producers exceeded their wellhead revenues by $7.8 billion. Reserves found today will require many years of development and investment of capital many times that required for the initial discovery before beginning to return the investment and often the full investment is never recovered. Unless the tax treatment of both expenditures for, and income from, petroleum production recognize this fact, exploration and development activity will be in a downward spiral with annual reserve additions never equalling production. Thus, dependence on foreign produced energy will increase. To respond to the issues being considered by this Subcommittee, we have divided our testimony into five major points.

### *I. The reason for granting tax incentives for oil and gas producers are as compelling today as when those incentives were first enacted*

Talk of a so-called "oil glut" had led to a dangerous complacency in the country. In fact, we are still importing too much crude at a cost which is a major cause of a chronic balance of payments deficit. The so-called "oil glut" has in no way eliminated this nation's vulnerability to supply interruptions and price escalations. We must be mindful that there is no "oil glut" in the United States; instead there is an unacceptable production deficiency that must be made up with imported oil. Last year we imported one-third of our oil requirements at a cost of $60 billion. Our allies of Europe and Japan imported 90 percent of their oil requirements at a cost of $150 billion. To minimize our import dependence by maintaining our imports at current levels or lower over the next decade, domestic production would have to increase to 11.4 million barrels per day to meet our needs. Because of the national decline in production from existing wells this would mean 13 million barrels of oil per day of new reserves will be needed. Stated another way, we will need 590,000 new wells drilled in the lower 48 states and an investment of $495 billion to meet our needs over the next decade.

### *II. Tax incentives should be evaluated considering the economic impact of increased drilling activity*

In evaluating these tax provisions, one major point should be considered. These incentives were each enacted with a major purpose in mind and in the case of the domestic oil and gas industry, these purposes are being achieved exactly as intended. The levels of drilling that have resulted from high levels of investment—made possible by these tax incentives—has had a dramatic payoff both in macroeconomic terms and in various local economies around the country. For example, based on the experience of recent years, for each 1 billion dollars spent on finding and developing crude oil and natural gas, an additional 20,000 barrels of daily production of crude oil equivalent can be established during the next 10 years. This production will back out 2.9 billion dollars in imports.

In addition to these benefits on the macroeconomic level, it should also be noted that the money spent on increased drilling is injected into the local economy for new jobs, increased local taxes, fees to landowners, fees to oilwell servicing companies, and money spent buying the goods and services needed for both drilling and production facilities. We use an actual case to show a detailed breakdown of where the money goes to drill a well.

### *III. A strong relationship exists between government tax policy (both positive and negative) and the results sought to be achieved*

Tax incentives for producers have proven to be an efficient vehicle of accomplishing the objectives of government policy. The close relationship between government tax and pricing policy and the industry response is demonstrated in research and by historical example. For instance, oil and gas depletion was singled out for reduction in 1969, and this action was followed in 1970 and 1971 successively by the two largest drops in exploratory drilling in the history of the industry even though both crude oil and natural gas prices increased each year.

The evidence is overwhelming that through tax policy Congress can either encourage or discourage domestic exploration and production. However, for more than a decade, U.S. tax policy for domestic crude oil and natural gas producers has been decidedly negative. It is clear that with the industry in the most dramatic curtailment in history, this is no time to even consider precipitous tax changes.

### *IV. Differences in the tax treatment of various segments of the industry are a rational attempt to reflect differences in the characters of these segments*

Our tax policy has also been guided by a desire to tax all enterprises in a manner which reflects their unique characteristics. The option to currently expense intangible drilling and development costs has existed under the Treasury regulations since the earliest Revenue Acts, although it was not formally incorporated in the statutes until 1954. These early regulations recognized the unique risks inherent in the exploration process and provided that all costs incurred in making wells capable of production, but which had no salvage value, could be currently charged to expense.

In addition to the options to currently expense intangible drilling and development costs, percentage depletion is a highly efficient incentive mechanism. For independent producers subject to the 50 percent marginal income tax rate it requires as much as $2.85 in additional selling price to replace each dollar in lost percentage depletion. The impact of percentage depletion has been widely recognized and it is now available to some 105 different minerals. The incentive provided by depletion is well established and the principle of depletion itself is very rarely questioned in Congress.

A producer must have some incentive to risk his capital, his reputation, the capital of his friends and the tolerance of his banker on a venture with a statistical probability of failure. Four out of five exploratory wills are dry holes. Some 20 percent of development wells drilled in known producing areas prove to be dry and a significant percentage of these development wells are completed as producers yet never produce enough oil and gas to pay for their costs. All oilmen experience losses and to cover these losses the successes need to provide more than a recovery of capital before the ordinary tax rates are imposed. Percentage depletion provides this.

Historically, independent producers have concentrated their efforts in the petroleum industry's high risk section—that is, exploration and development—and they have always been responsible for the majority of exploratory wells. Figures for the period from 1969 to 1978 indicate that this remains true. During that time independent producers drilled 85 percent of the new field wildcat wells in the country, while the major companies accounted for 10.5 percent.

The aggressive exploration efforts of independent producers can perhaps be best demonstrated by a comparison of the aggregate gross income from the sale of oil and gas to the aggregate expenditures for finding, developing and production costs. For at least the past decade independent producers have demonstrated a remarkable consistency in reinvesting funds in new exploration, drilling and development activity equal to their gross wellhead revenues. These amounts, multiplied throughout our economy provide needed jobs, develop additional domestic energy production, and reduce our dependence on high cost insecure foreign oil.

Without this reinvestment rate our domestic discoveries will not be adequate to maintain production and this reinvestment rate cannot be maintained without sufficient cash flow from current operations. It is vitally important to the nation's energy security for producers to again see a period of stable tax policy without the seemingly annual tax changes threatening the already inadequate cash flow position of most petroleum explorer-producers.

### *V. Proposals to change tax incentives add uncertainty of tax treatment to the existing crude oil price uncertainty—these Factors exacerbate negative trends in an industry already crippled by recession*

The real problem facing producers is one of economics. Developing less and less accessible reserves will cost more and more money. The availability of capital, not the availability of acceptable drilling prospects, presents the greatest obstacle to exploratory drilling, and exploratory drilling has historically been the province of the independent producer.

Unlike an integrated oil company which has opportunities to profit from the refining of oil, transportation of products to the marketplace and retail sales of consumer products both in the U.S. and throughout the world, the independent produced can obtain his revenues only from sales at the wellhead and only in the United States. It is these revenues which must provide the capital for continued exploration, yet currently nearly half of the value of a barrel of oil disappears before it reaches the producer. On the average, fifteen percent of every barrel is returned to the mineral owner in the form of royalties and on newly leased acreage these royalty payments may be much higher. Seven percent of every barrel is paid to state and local governments in production and severance taxes, and these levies have also been steadily increasing. Finally, 23 percent of the barrel is paid out in windfall profit taxes, the largest and most complicated tax ever assessed against any industry.

It is only from this remaining fifty-five percent of the barrel that the independent producer can pay the costs of production, drilling and development, his income taxes, support his family and finance the next wildcat.

Exploration and drilling for oil and natural gas is a "current cash" business. Wildcat wells are not drilled with borrowed money—the producer must use internally generated cash flow from current sales of oil and gas, augmented with funds from outside investors. Every dollar of income diverted to taxes reduces, by at least a dollar and usually more, expenditures for exploration and drilling.

The sources of the cash flow have shrunken drastically in the last fourteen months. The decline in crude oil prices in response to the so-called "oil glut" induced by the world wide recession has reduced the wellhead value of production by $12 billion. This precipitous fall in available funds has had a predictable impact on drilling activity. By any measure the industry is in the midst of a deep and severe recession. The number of active drilling rigs has fallen from its peak of 4,530 in 1981 to only 1,840 in April 1983.

Maintaining our domestic production is not just a matter of increasing the expenditures of our existing producers. We must also expand the number of operators. It is these new entrants and emerging enterprises for whom the existing tax incentives are both the most necessary and the most beneficial. Without these incentives, the industry will never attract the capital to achieve energy security.

## STATEMENT

My name is Sidney J. Jansma, Jr., an independent oil and gas producer from Grand Rapids, Michigan. I am appearing here as vice chairman of the Tax Committee of the Independent Petroleum Association of America (IPAA), a national organization of independent explorer-producers, having almost 8,000 members in every producing area in the nation. Together with the twenty-nine unaffiliated state and regional associations which join us in these comments, we represent essentially all of the 15,000 independent oil and gas producers who account for about 90 percent of all the drilling in the United States. We welcome and appreciate this opportunity to express our views on tax policy issues under consideration by this committee.

The Subcommittee's April 15th press release announcing today's hearings states that the Subcommittee will inquire into whether the present tax treatment of oil and gas producers is good tax and energy policy, and whether the specific provisions providing different tax treatment work as they were intended. IPAA believes that these tax incentives are a vital force in encouraging investment of the unprecedented amounts of capital required over the next decade to develop our domestic energy resources and achieve our economic and energy policy needs. This will require not only maximum utilization of internally generated revenue, but also attracting very substantial amounts of funds from outside investors. We want to emphasize that a dollar invested in exploration and development of crude oil and natural gas does not result in a dollars worth of oil and gas being produced. Over the past decade for example, the $116.8 billion spent by independent producers exceeded their wellhead revenues by $7.8 billion. Reserves found today will require many years of development and the investment of capital many times that required for the initial discovery before beginning to return the investment and often the full investment is never recovered. Unless the tax treatment of both expenditures for, and income from, petroleum production recognize this fact, exploration and development activity will be in a downward spiral with annual reserve additions never equalling production. Thus, dependence on foreign produced energy will increase.

Generally, energy tax policy should be designed to:

- Extend the economic life of existing energy producing properties;
- Encourage development of discovered but undeveloped high costs reserves;
- Stimulate investment in wildcat drilling to expand produceable reserves;
- Attract the investment of risk capital from outside the petroleum industry;
- Recognize both the ever-rising costs of replacing energy supplies currently consumed and the need to overcome the inertia of years of declining exploration and development.

Policies intended to accomplish these objectives must take into account certain basic characteristics of oil and gas exploration and development, i. e.:

- Exploration for and development of crude oil and natural gas resources are both capital intensive and high risk;
- The long lead times before investment generates significant return compounds both the risk and capital requirements;
- Unlike most industrial enterprises, the successful ventures (producing wells) must not only be self-sustaining, they must also pay for the unsuccessful ventures (dry holes);

- Potential investment in exploration and development must compete with other investment opportunities, many with equal or higher potential rates of return but none with the high risk of wildcatting.

To respond to the issues being considered by this Subcommittee, we have divided our testimony into five major points:

> First, the reasons for granting tax incentives for oil and gas producers are as compelling today as when those incentives were first enacted.
>
> Second, the tax incentives should be considered in the context of the increased economic benefits to the general economy which result from increased drilling activity.
>
> Third, the tax incentives are an efficient tool in that a strong relationship exists between government tax policy and the results sought to be achieved.
>
> Fourth, the differences in the tax treatment among various segments of the industry are a rational attempt to reflect the character of these segments.
>
> Fifth, proposals to change tax incentives add tax uncertainty to price uncertainty. These negative factors exacerbate negative trends in an industry already crippled by recession.

Mr. Chairman, I would now like to discuss these points in more detail.

## I. THE REASONS FOR GRANTING TAX INCENTIVES FOR OIL AND GAS PRODUCERS ARE AS COMPELLING TODAY AS WHEN THOSE INCENTIVES WERE FIRST ENACTED.

In World War I, Winston Churchill, then Naval Minister of Great Britain, recognized that control of access to petroleum reserves was essential to the conduct of war and maintenance of national security. Following the war, Great Britain launched an aggressive policy of encouraging its oil companies to search the world for oil and natural gas. Today Great Britain is an energy exporter.

This early lesson was not lost on U.S. policy makers. It was after World War I that Congress fashioned the main tax incentives for the domestic petroleum industry. These incentives included recognition of the intensive capital requirements of finding and developing oil and natural gas and the depletable nature of the resource. Thus, the concept of current expensing of intangible drilling and development costs, together with statutory depletion, have been part of our income tax code from very near its inception.

These incentives were grounded in the sound principle that it was in the best interest of national defense and economic stability to develop our secure, indigenous resources of oil and natural gas.

In more recent years there has been an unfortunate and growing trend to consider energy tax policy in the context of how much revenue can be extracted from energy producers. Unreasonable taxation of energy producers is self-defeating. It reduces energy development and production, thereby increasing dependence on more costly alternatives including imported oil and natural gas. This in turn lowers general economic activity and ultimately reduces revenues to government. There has been an increasing tendency to confuse energy policy with social policy. This has resulted in taxing energy production to subsidize energy consumption thus giving consumers a false impression about the cost of energy, which both increases consumption and decreases supply.

Mr. Chairman, talk of a so-called oil glut has lead to a dangerous complacency in the country. In fact, we are still importing too much crude at a cost which is a major cause of a chronic balance of payments deficit. The so called "oil glut" has in no way eliminated this nation's vulnerability to supply interruptions and price escalations. We must be mindful that there is no "oil glut" in the United States; instead there is an unacceptable production deficiency that must be made up with imported oil.

Our nation is still dangerously vulnerable. Henry Schuler, an energy expert with the Center for Strategic & International Studies (CSIS), details our vulnerability this way:

> Last year (1982), we imported one-third of our oil requirements at a cost of $60 billion. Our allies of Europe and Japan imported 90% of their oil requirements at a cost of $150 billion. But beyond those direct costs, there are indirect costs because the source of that oil is really among the most fragile areas of the world. And to emphasize that in point of fact half the oil moving in world trade still comes from the Middle East. If you add the Arab countries outside the Middle East such as Egypt, Tunisia, Algeria and Libya, you come up with two-thirds of the oil moving in world trade.

In other words, in addition to the dollar amount and the volume of United States imports, we also remain vulnerable because of our allies' dependence on petroleum from unstable areas of the world and our heavy participation in world economic and financial markets.

While we are all aware of the projected budget deficits which have been getting so much attention in the press lately, we should also note the indirect costs associated with our dependence on Middle Eastern imports. The military costs of protecting the Middle East region are enormous. This includes the costs of men, military hardware and maintenance of an active military and naval presence in the area. The Rapid Deployment Force is just one element of that cost. Diplomatic costs make up another. Again, Henry Schuler of CSIC details these costs:

> Among the hidden costs associated with this dependence upon Middle Eastern imports are the military and maritime costs. Procurement costs alone of the rapid deployment force is $40 billion over the next six years.
>
> Beyond the military and maritime costs, there are diplomatic costs. We have to make foreign policy concessions in an effort to satisfy oil producers. And I'm not just talking about the Middle East. I'm talking about Southern Africa and Central America; all areas where these considerations come into play...

Mr. Chairman, IPAA believes that policy changes affecting energy taxes must not be based on short term budget, deficit, and revenue considerations but on meeting our energy goals over the next 15 years and into the long term.

The task before us is enormous. If the current level of crude oil production is projected into the future assuming a 2 percent annual increase in oil consumption, our imports will rise again to an unacceptable level. As shown on Chart 1, the increase in imports will rise from our current level of 30 percent to 46 percent, the approximate level of import dependence in 1978.

## U.S. OIL CONSUMPTION, 2% GROWTH

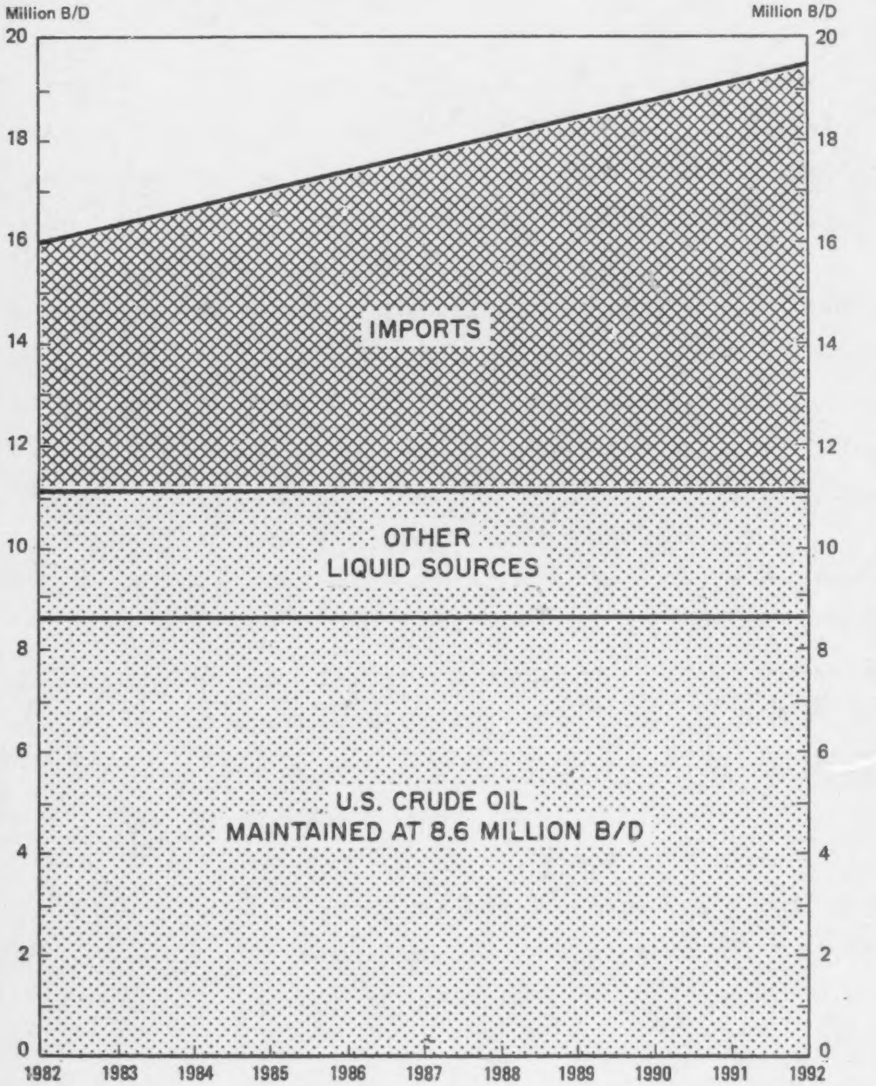


CHART 1

IPAA CHART
MAY 1983

A 2 percent increase of consumption, per year, is a plausible assumption given the problems that have arisen with the alternative fuels, such as nuclear, coal, and shale. If energy consumption rose the lack of these alternatives would cause an increase in oil demand. As import levels rose from the 30 percent mark in the early 1970's, the United States became vulnerable to interruptions in our supplies of crude oil and products. This culminated when we became dependent on outside supplies for 46 percent of our needs. At this point the price was doubled causing a violent downward reduction in demand for oil. If consumption rises as we project, then we will once again be vulnerable to international reactions. Obviously, we should take policy actions to prevent our energy security from eroding to that extent. A more desirable path is to minimize our import dependence by maintaining our imports at current levels or lower over the the next decade. To do this, domestic production would have to increase to an average rate of 11.2 million barrels per day in 1992 to meet our needs. To move from our present rate of about 8.7 million barrels per day and also make up the loss due to the natural production decline of existing wells will require adding 7.9 million barrels per day of new production in 1992 (Chart 2). Stated another way, we will need 890,000 new wells drilled in the lower 48 states and an investment of $495 billion to meet our needs over the next decade (Chart 3). But, even to maintain our current levels of domestic production, we will need 570,000 wells and $336 billion dollars in investment over the next decade.

## U.S. OIL CONSUMPTION, 2% GROWTH HOLDING IMPORTS AT 30% LEVEL

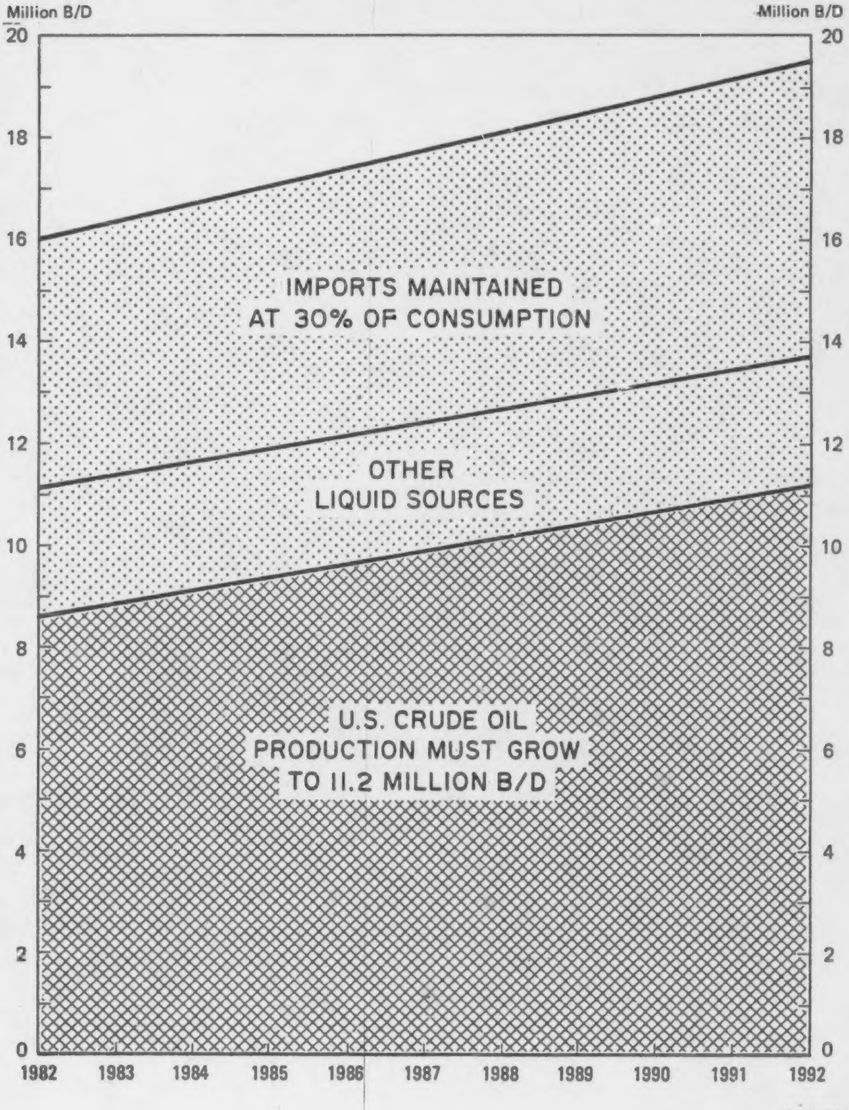


CHART 2

IPAA CHART
MAY 1983

# PRODUCTION NEEDS TO MAINTAIN IMPORTS AT 30% LEVEL WITH A 2% INCREASE IN DEMAND

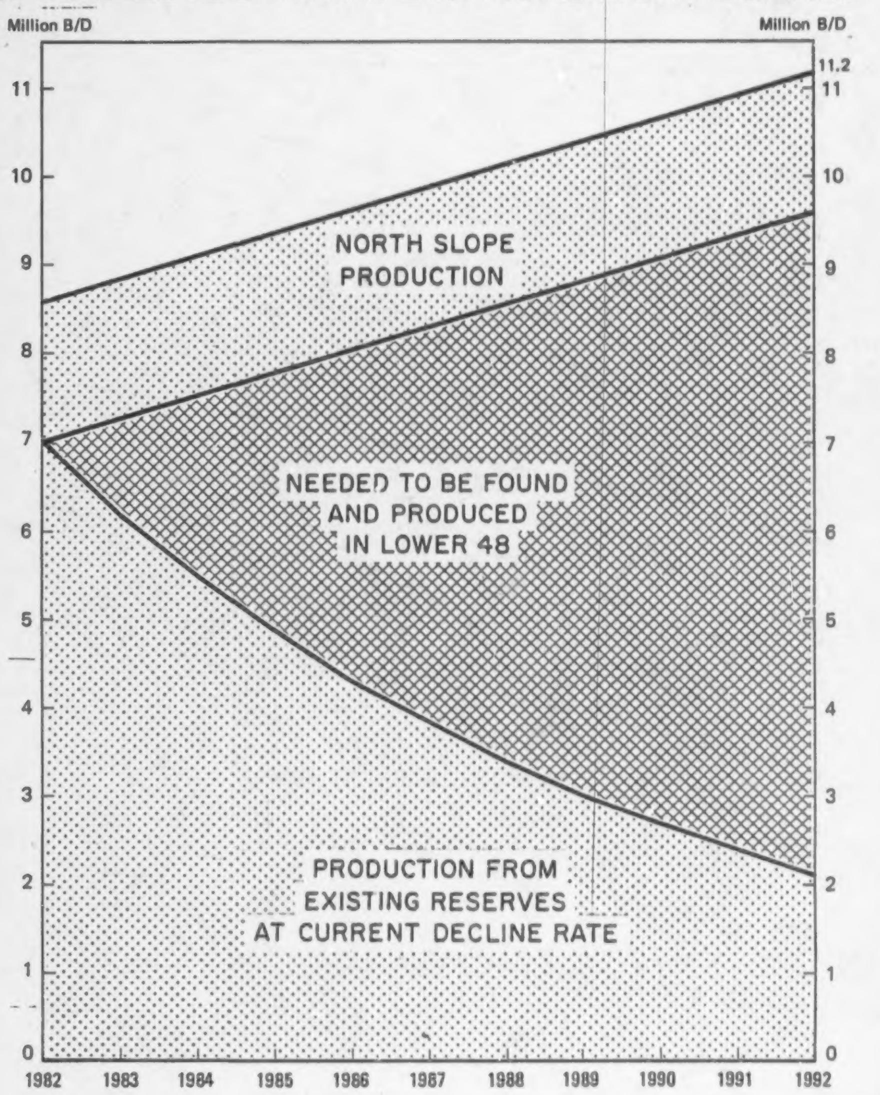


CHART 2A

IPAA CHART
MAY 1983

# ALTERNATIVE REQUIREMENTS

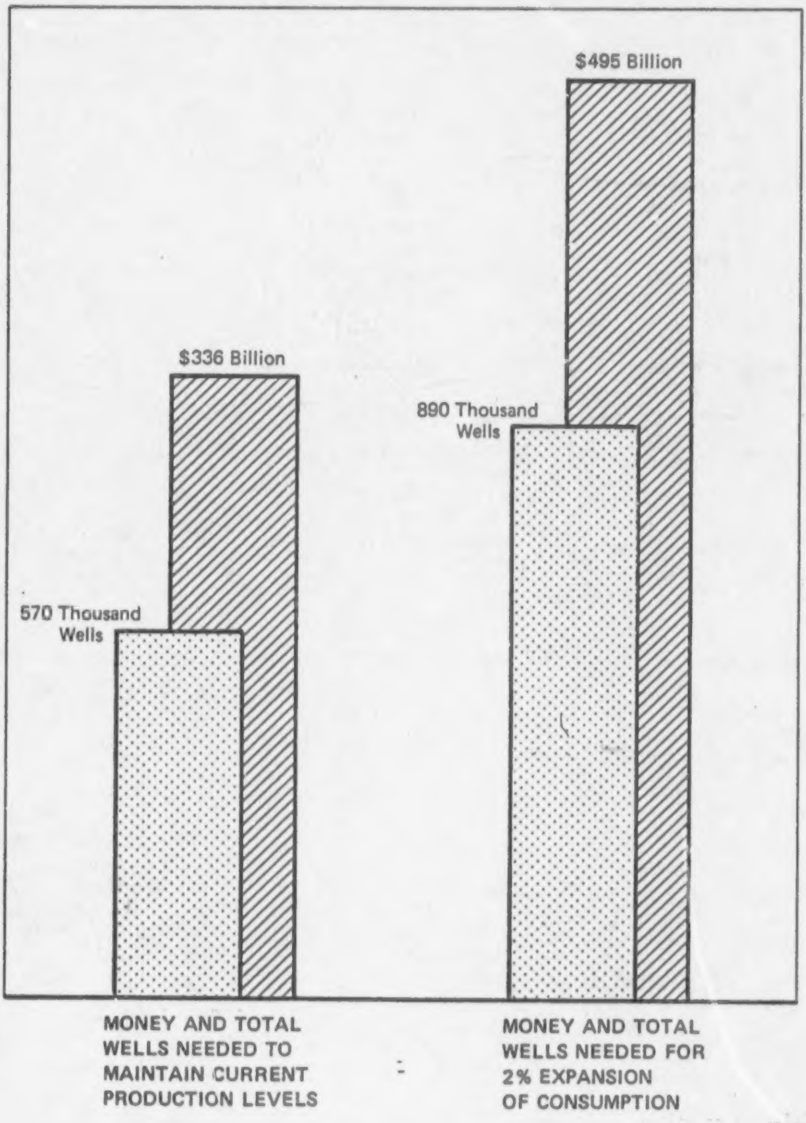


CHART 3

IPAA CHART
MAY 1983

Since 1957, there have been 12 disruptions in crude oil supply from the Middle East. Because we had adequate or excess crude oil producing capacity through the first 10, we were severely impacted only by the last two in 1973 and 1979. Based on this kind of record, it would be foolhardy to assume that we will not face similar supply crises in the future. The question is not whether there will be a major crude oil disruption, but when that disruption will occur. While there has been great hope expressed about diversifying our domestic energy sources, this has not happened. Nuclear power has been stalemated. Transportation and environmental concerns have limited use of coal and the synfuels industry has collapsed. The importance, therefore, of oil and gas in meeting our economic and defense needs for the rest of the century cannot be overstated.

## II. TAX INCENTIVES SHOULD BE EVALUATED CONSIDERING THE ECONOMIC IMPACT OF INCREASED DRILLING ACTIVITY

Mr. Chairman, as you know in recent years some elements of our tax structure have come to be identified as "tax expenditures" and receive special attention in the budget. "Tax expenditures" is a contradiction in terms. It is a concept based on the idea that all income belongs to the government and whatever portion of your income you are allowed to keep is a "tax expenditure." On March 7, the Congressional Joint Committee on Taxation published its annual estimates of federal "tax expenditures." We believe that in evaluating these tax provisions, one major point should be considered. These incentives were each enacted with a major purpose in mind and in the case of the domestic oil and gas industry, these purposes are being achieved as intended. These figures purport to estimate revenue loss to the government but without taking account of the economic benefits to the nation of having that purchasing power invested in the private sector. In the case of oil and gas exploration, the drilling that has resulted from high levels of investment -- made possible by these tax incentives -- has had a dramatic payoff both in macroeconomic terms and in various local economies around the country.

Consider the following facts:

- Based on the experience of recent years, for each 1 billion dollars spent on finding and developing crude oil and natural gas, an additional 20,000 barrels of daily production of crude oil equivalent can be established during the next 10 years. This production will back out $2.9 billion in imports.
- In 1980 the domestic oil industry added crude reserves equivalent to production for the first time since 1966.
- Increasing the supply of domestic petroleum has not only benefited those industries that use energy as a significant element in production, but also other industries more directly. For example, the petroleum industry is an important user of steel. During the period from 1976 to 1981 this use tripled.
- After the recession hit the domestic oil industry, Economist Sam I. Nakagama of Kidder, Peabody and Company was quoted in Business Week magazine on the macroeconomic impact.

> "Even more significant, in Nakagama's eyes, are the effects of the oil sector and the trade balance on business activity. Last year oil and gas drilling far outweighed the impact of either the auto or steel industry on the economy. Indeed, in December it accounted for 1.94% of industrial production--more than autos and basic iron and steel put together. With the recent drop in oil prices, notes Nakagama, drilling activity has plunged by about 20% since late December, undermining a major source of economic strength (April 26, 1982, page 127)."

In addition to these benefits on the macroeconomic level, it should also be noted that the money spent on increased drilling is injected into the local economy for new jobs, increased local taxes, fees to landowners, fees to oilwell servicing companies, and money spent buying the goods and services needed for both drilling and production facilities. In Chart 4 we use an actual case to show a detailed breakdown of where the money goes to drill a well.

# Where does the money go?

## Expenditures for Drilling

#1 George Wild Well
Acadia Parish, La.

Payroll, Taxes, Employees & Vehicles
Used Collectively Within State of La.

| Payee | Well Cost | Employees | $ Payroll | Taxes & Insurance | Vehicles |
|---|---|---|---|---|---|
| Vacuum Trucks & Storage | 1,772.91 | 345 | 3,600,000 | 648,000 | 113 |
| Pump Rentals | 8,935.68 | 67 | 1,262,100 | 277,178 | 34 |
| Liquid, Mud, Drilling Fluid & Service | 391,855.10 | 54 | 1,197,000 | 215,460 | 56 |
| Trucking, Hauling & Hot-Shot Service | 12,512.06 | 1,372 | 32,293,460 | 5,812,822 | 1,478 |
| Lay-Down Machine | 9,892.70 | 43 | 826,000 | 148,680 | 41 |
| Location Work | 54,484.10 | 1,058 | 14,464,730 | 2,603,650 | 295 |
| Drilling Contractor with Rig | 493,875.35 | 143 | 4,121,000 | 741,780 | 35 |
| Drill Bits | 35,162.80 | 1,550 | 25,000,000 | 4,500,000 | 265 |
| Professional Services* | 152,153.56 | 42 | 1,141,000 | 166,500 | 12 |
| Pipe & Wellhead Purchases | 320,174.76 | 115 | 2,700,000 | 486,000 | 40 |
| Pipe & Hole Support Service | 42,909.90 | 1,569 | 30,239,044 | 4,633,026 | 570 |
| Cementing | 45,095.75 | 174 | 4,500,000 | 810,000 | 90 |
| Rental Tools | 111,887.53 | 1,501 | 10,665,409 | 1,919,770 | 1,217 |
| Logging & Well Testing | 39,807.37 | 2,050 | 20,000,000 | 3,600,000 | 155 |
| Other Contract Service | 3,434.50 | 182 | 4,040,000 | 727,200 | 67 |
| Miscellaneous Rig & Well Supplies | 7,530.84 | 100 | 1,865,000 | 336,200 | 120 |
| GRAND TOTAL | $1,731,484.91 | 10,365 | $157,914,743 | $27,626,266 | 4,588 |

*Leases & rentals, survey & engineering, legal, supervision, operations, management, & accounting

CHART 4

June 1980

## ONE WELL

### Where the Money Goes

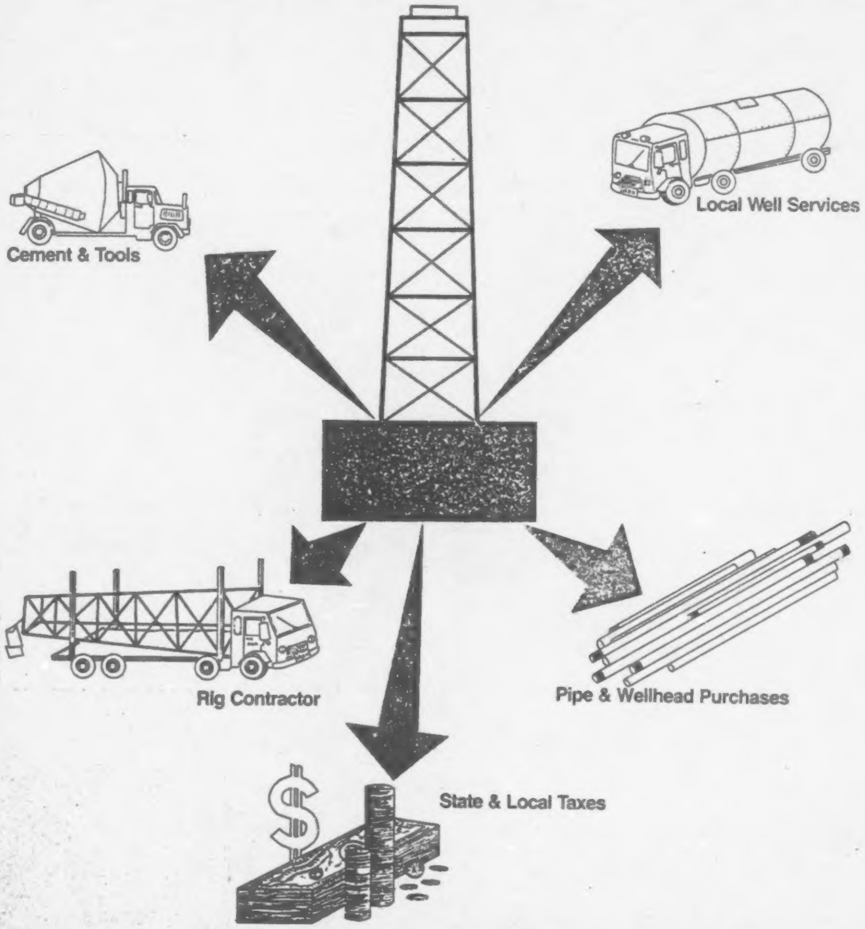

Local Well Services
Cement & Tools
Rig Contractor
Pipe & Wellhead Purchases
State & Local Taxes

CHART 4A

Although this well turned out to be a dry hole, there was still a significant benefit to the local economy. To illustrate how these costs filter through the local economy, the Chart shows well costs spent on services, and to illustrate the impact of such expenditures on the economy shows the number of employees of the contractor utilized, his approximate annual payroll, tax, and insurance costs and number of vehicles operated in one state. If this well had been a producer, additional costs of some $1,000,000 could be added for completing and equipping the well for production and for additional taxes.

Again, Mr. Chairman, the point I am making is that the money that is used to increase domestic drilling activity goes directly into small businesses and the local economies where these wells are drilled.

## III. A STRONG RELATIONSHIP EXISTS BETWEEN GOVERNMENT TAX POLICY (BOTH POSITIVE AND NEGATIVE) AND THE RESULTS SOUGHT TO BE ACHIEVED.

Tax incentives for producers have proven to be an efficient vehicle of accomplishing the objectives of government policy. The close relationship between government tax and pricing policy and the industry response is demonstrated in research and by historical example.

For example, a 1975 Ford Foundation Energy Policy Project published a collection of essays called Studies in Energy Tax Policy which showed the responsiveness of oil supply to tax and price changes. Similarly, in a Brookings Institution Paper entitled "Oil Supply and Tax Incentives," Edward Erickson, Robert Spann and S. W. Millsaps proved that percentage depletion increases the quantity of crude oil supplied compared to a situation with uniform cost-depletion tax treatment. Similar results were found by Paul MacAvoy and Robert Pindyck in their study of natural gas, "Alternative Regulatory Policies For Dealing With The Natural Gas Shortage."

In their analysis, "The Cost-Effectiveness of Federal Tax Subsidies for Petroleum Reserves," James Cox and Arthur Wright produced widely-accepted empirical evidence that both percentage depletion and the expensing of intangible drilling costs have a statistically significant positive effect on the amount of proved crude oil reserves. They found that an equally significant positive relationship exists between these two tax incentives and the rate of net investment in proved reserves through drilling. Among others, a later study by Cox and Wright points out the deleterious effects of the windfall profit tax on the crude oil producing industry in terms of both exploration and production incentives.

The research literature is replete with empirical documented studies such as these that prove the power of fiscal tax policy to alter the market signals that oil producers must face in the course of doing business. This research is supported by vivid historical examples.

Consider two illustrations:

(1) Oil and gas depletion was singled out for reduction in 1969, and this action was followed in 1970 and 1971 successively by the two largest drops in exploratory drilling in the history of the industry even though both crude oil and natural gas prices increased each year.

(2) In 1976, exploration and development expenditures by independent producers increased by 71 percent over the previous year, 1975. But in October 1976, Congress subjected intangible drilling costs to the 15 percent minimum tax, and in 1977 exploration/development expenditures by independents increased by only 6 percent from the previous year in spite of an attractive 15 percent increase in the composite price of oil and natural gas.

Recognizing that this latter provision impacted most severely on those most vigorously exploring for new petroleum resources, Congress partially corrected the disruptive impact of the minimum tax on IDC's in 1977. These examples are only two of the many instances over the past decade where producers have had to overcome negative tax policy.

The evidence is overwhelming that through tax policy Congress can either encourage or discourage domestic exploration and production. However, for more than a decade, U. S. tax policy for domestic crude oil and natural gas producers has been decidedly negative.

- October 1969 - Applicable rate of percentage depletion cut from 27 1/2 percent to 22 percent. Percentage depletion also made subject to the "minimum tax" provision.
- March 1975 - Percentage depletion eliminated entirely for about 85 percent of domestic oil and natural gas production. Percentage depletion left intact for producers of over 100 other minerals.
- September 1976 - Intangible drilling costs retroactively made subject tominimum tax provisions. Percentage depletion further restricted for independent producers and royalty owners by so-called 65 percent limitation.
- March 1980 - Crude Oil Windfall Profit Tax Act adopted, imposing an excise tax on domestically produced crude oil - but not foreign produced crude oil.
- January 1981 - Applicable rate of percentage depletion begins phase-down from 22 percent to 15 percent by 1984.
- August 1981 - Minimum tax on intangible drilling costs and percentage depletion increased for individuals: corporations denied current deductibility of some intangible drilling costs.

It is clear that with the industry in the most dramatic curtailment in history, this is no time to even consider precipitous negative tax changes.

## IV. DIFFERENCES IN THE TAX TREATMENT OF VARIOUS SEGMENTS OF THE INDUSTRY ARE A RATIONAL ATTEMPT TO REFLECT DIFFERENCES IN THE CHARACTERS OF THESE SEGMENTS.

The role of tax policy in providing incentives to channel private investment in a manner which reflects the goals of public policy has been recognized as a fundamental of taxation since the inception of the income tax. U.S. tax policy has also been guided by a desire to tax all enterprises in a manner which reflects their unique characteristics. There are numerous examples of specific provisions of the Internal Revenue Code which were enacted in recognition of these principles. A system of credits has been used to spur investments in productive capacity, to encourage research and development, to increase energy conservation, to speed pollution control, to target the hiring of hard core unemployed, to cite only a few of many examples. Different taxing schemes have also been adopted to account for fundamental differences in the nature of such businesses as public utilities, farmer's cooperatives, banks, savings and loan associations, insurance companies, real estate investment trusts, and the list could continue.

These principles likewise influenced the taxation of the petroleum industry from the beginnings of the income tax. The option to currently expense intangible drilling and development costs has existed under the Treasury regulations since the earliest Revenue Acts, although it was not formally incorporated in the statutes until 1954. These early regulations recognized the unique risks inherent in the exploration process and provided that all costs incurred in making wells capable of production, but which had no salvage value, could be currently charged to expense. There were no major changes in the treatment of intangible drilling costs until 1976.

Recognition of depletion has a similarly lengthy history. When the 16th Amendment authorized the tax on "incomes", Congress was careful to distinguish between capital and income. The concept of statutory depletion was adopted as the means to recognize consumption of a physical asset as it is removed or produced from the ground. Between 1913 and 1926, several changes were made in the method of determining and accounting for depletion. All proved to be administratively burdensome and expensive to use both for taxpayers and the government. Following a lengthy special study by a select congressional committee, it was determined that the value of individual producing properties bore a reasonably consistent relationship to the price of crude oil and natural gas at the wellhead. Accordingly, in 1926 the present method of computing depletion by deducting a stated percentage of gross income at the time of sale was established. No major change was made until 1969 when the applicable rate was reduced from 27 1/2 percent to 22 percent.

Percentage depletion is a highly efficient incentive mechanism. The impact of percentage depletion has been widely recognized and it is now available to some 105 different minerals. The incentive provided by depletion is well established and the principle of depletion itself is very rarely questioned in Congress. Depletion for oil and gas, however, has been repeatedly singled out for legislative revision and the incentive it provides has been steadily eroded. For independent producers subject to the 50 percent marginal income tax rate it requires as much as $2.85 in additional selling price to replace each dollar in lost percentage depletion. Availability of percentage depletion is especially important in a time of unstable and declining prices.

The option to deduct intangible drilling costs and the recognition of depletion are not the product of congressional favoritism to a special class of taxpayer. These provisions have endured through seventy years of economic change only because they make good sense. These provisions, although perhaps imperfect, exist in recognition of the need to provide incentives for exploration and development of crude oil and natural gas. It goes without saying that in the absence of the spending thus generated we are simply liquidating our known reserves.

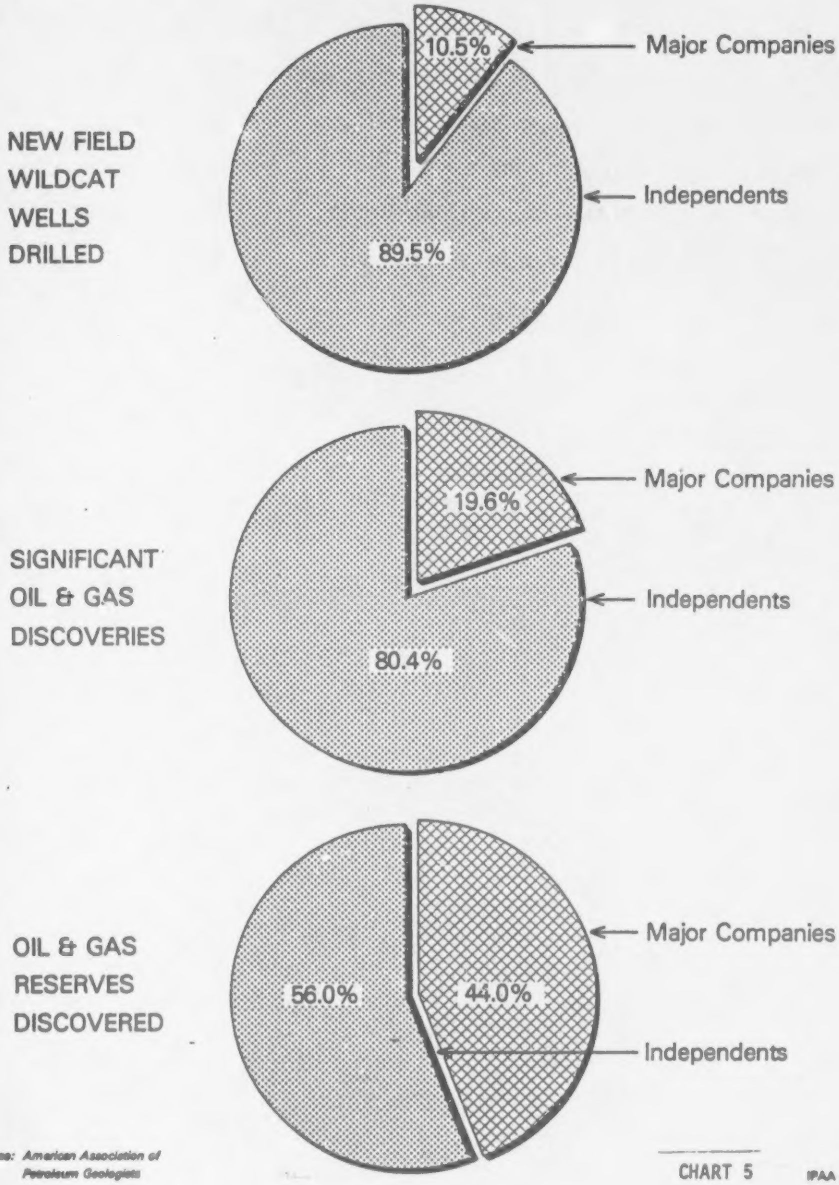
A producer must have some incentive to risk his capital, his reputation, the capital of his friends and the tolerance of his banker on a venture with a statistical probability of failure. Four out of five exploratory wells are dry holes. Some 20 percent of development wells drilled in known producing areas prove to be dry and a significant percentage of development wells are completed as producers yet never produce enough oil and gas to pay for their costs. They do , however, add significantly to our reserves and daily production. As shown above, the funds spent in drilling and completion add significantly to employment and the economy. All oilmen experience losses and to cover these losses the successes need to provide more than a recovery of capital before the ordinary tax rates are imposed. Percentage depletion provides this. Similarly, the continued expansion of exploration efforts requires that sufficient cash flow be available from income after taxes to pay for new wells. The option to deduct intangibles aids the producer in maintaining this cash flow.

Beginning in 1969 with the reduction in the rate of percentage depletion these historical incentives have been continually diluted. Subsequent legislation, however, almost uniformly recognized the special role and character of independent producers who are neither significant retailers or refiners. The difference in the treatment of independent producers is founded on sound logic.

Historically, independent producers have concentrated their efforts in the petroleum industry's high risk section -- that is, exploration and development -- and they have always been responsible for the majority of exploratory wells. Figures for the period from 1969 to 1978 indicate that this remains true. During that time independent producers drilled 89.5 percent of the new field wildcat wells in the country, while the major companies accounted for 10.5 percent (Chart 5). The results of that drilling show a similar pattern; independents during the same period accounted for 80.4 percent of the significant oil and natural gas discoveries, while the major companies were responsible for 19.6 percent (Chart 5). While the major companies accounted for 44 percent of the oil and natural gas reserves discovered during that time, independents were responsible for 56 percent (Chart 5).

# ROLE OF INDEPENDENTS

1969 – 1978

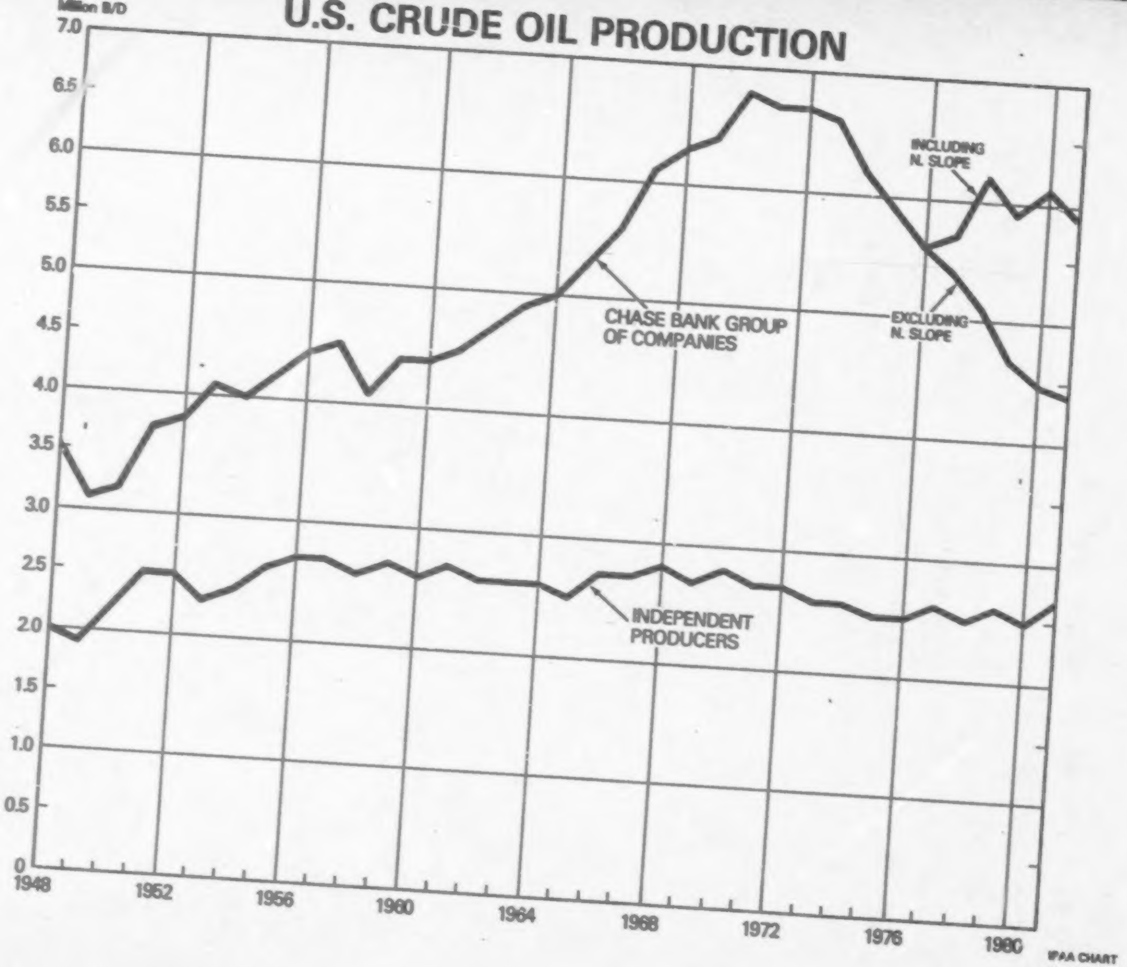


*Source: American Association of Petroleum Geologists*

CHART 5

IPAA CHART
March [illegible]

Throughout the 1950's and '60's the number of active independents was cut in half. Many of those remaining were forced to sell existing production to major companies in order to survive. Notwithstanding this, in absolute terms, independents' production has remained more or less constant since 1952. As a percentage of total domestic production, the independents' share has been rising for the last several years. Declines in domestic production that have been experienced since 1971 have been borne for the most part by the major oil companies (Chart 6).



U.S. CRUDE OIL PRODUCTION

CHART 6

Excluding production from the North Slope of Alaska, it is apparent that the only factor preventing domestic crude oil production from declining precipitously has been the activity of independent producers and their willingness to risk vast sums of money on the finding and development of reserves. The importance of the role played by independent producers in preventing a catastrophic fall in domestic production is further illustrated by their completions of both oil and natural gas wells (Charts 7 & 8).

## OIL WELL COMPLETIONS IN THE U.S.

(Chase Bank Group of Companies vs. Independent Producers)

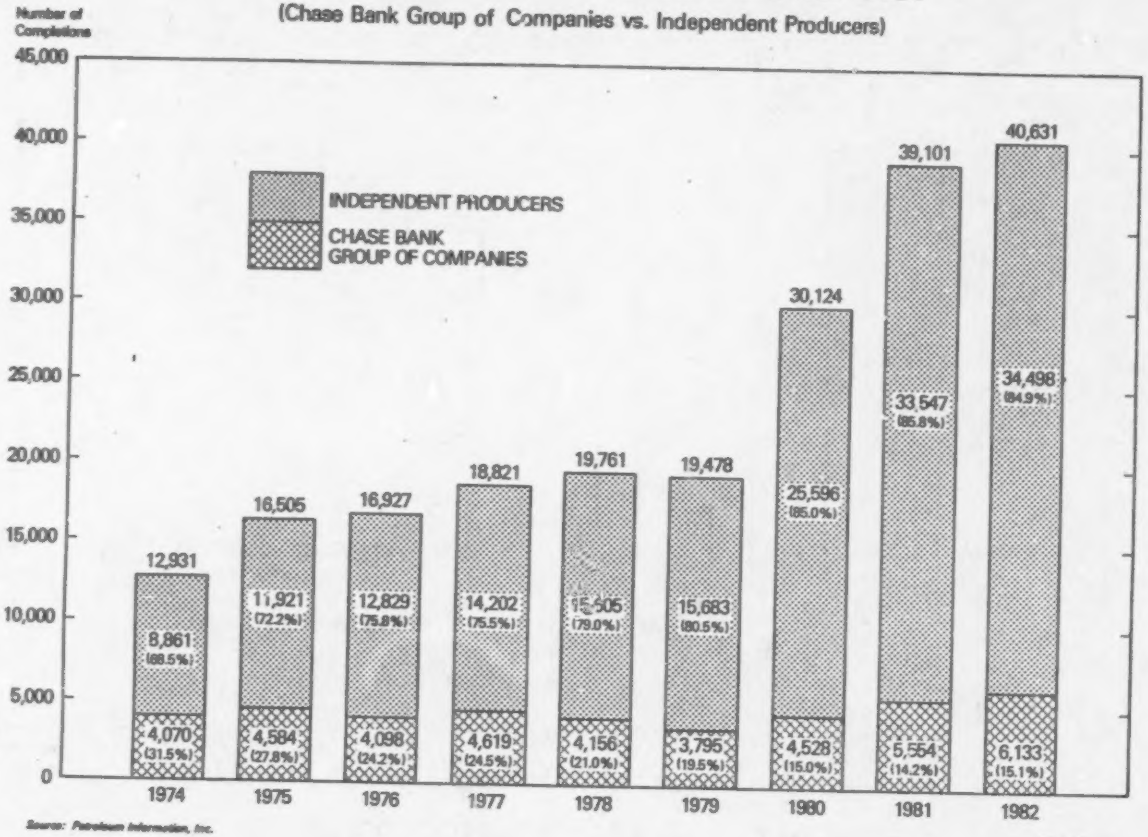


CHART 7

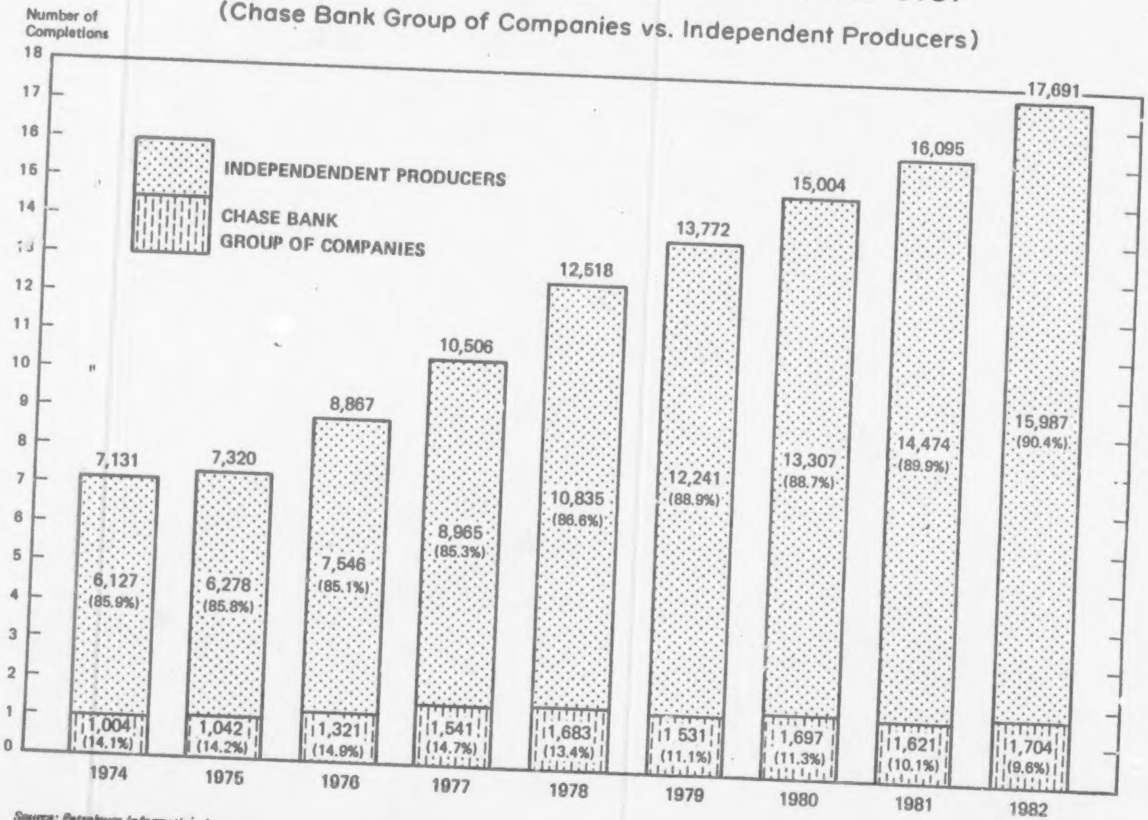
Source: Petroleum Information, Inc.

IPAA CHART
March 1983

CHART 8

## GAS WELL COMPLETIONS IN THE U.S.

(Chase Bank Group of Companies vs. Independent Producers)



*Source: Petroleum Information, Inc.*

IPAA CHART
MARCH 1983

In the years since 1974, their share of oil well completions increased from 68.5 percent to 85.8 percent in 1981. As a general rule, the major companies have concentrated their exploration efforts in areas considered likely to yield a "significant" discovery, such as Alaska and the offshore areas. The independent producer, however, has maintained his exploration efforts over a much broader geographical area and it is from these more modest successes that our domestic production has been maintained. Exploration and development onshore in the "lower 48" -- traditionally the province of independents -- does not require the very long lead times before production is realized. Thus, our daily production volume is sustained by the thousands of low volume "independent" wells while we wait the 5 to 10 years necessary for a Prudhoe Bay or Baltimore Canyon giant discovery to finally come on stream. This is not to say that independent producers do not make substantial discoveries, however. In recent years independent producers have been the leading drillers in such major areas as the deep Anadarko Basin in Oklahoma, the Austin Chalk in South Texas, and the Tuscaloosa Trend in South Alabama and Louisiana. Energy security will not be the result of a few spectacular discoveries, but will come from the multiplicity of effort of thousands of operators each adding their part to the total.

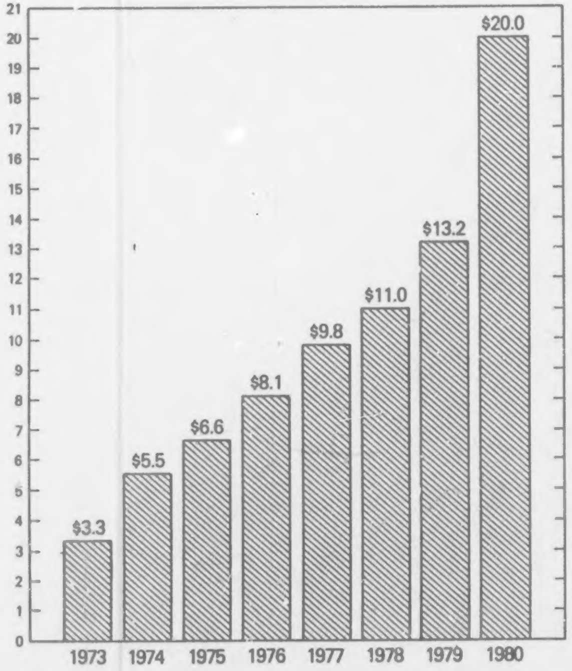
The aggressive exploration efforts of independent producers can perhaps be best demonstrated by a comparison of the aggregate gross income from the sale of oil and gas to the aggregate expenditures for finding, developing and production costs (Chart 9).

# INDEPENDENT OIL & GAS PRODUCERS

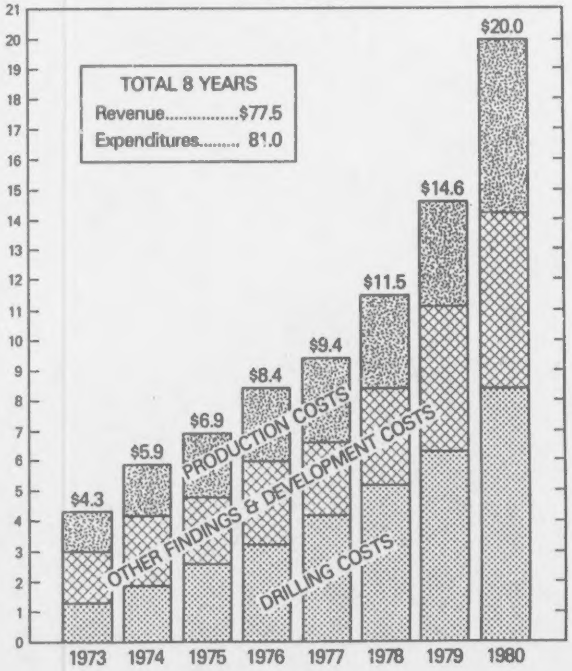
(ALL U.S. PRODUCERS EXCEPT THE 24 LARGEST COMPANIES)

1973 — 1980

WELLHEAD VALUE OF PRODUCTION
(Billion Dollars)



FINDING, DEVELOPING & PRODUCTION COSTS
(Billion Dollars)



TOTAL 8 YEARS
Revenue................$77.5
Expenditures......... 81.0

*Includes geological and geophysical; lease and land acquisition; test hole contributions, etc.*
*Source: U.S. Bureau of the Census, "Annual Survey of Oil and Gas".*

IPAA CHART
March 1983

# U.S. PRODUCERS' INCOME vs. INVESTMENT

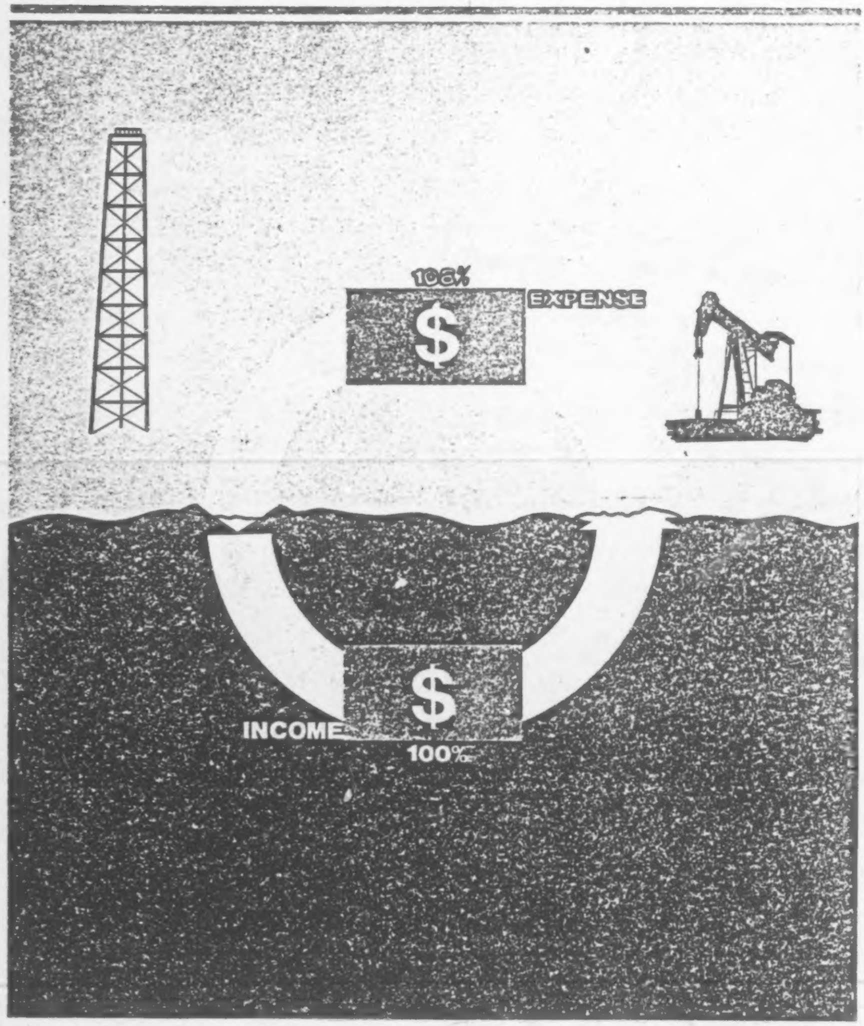


CHART 9A

For at least the past decade independent producers have demonstrated a remarkable consistency in reinvesting funds in new exploration, drilling and development activity exceeding their gross wellhead revenues. These amounts, multiplied throughout our economy provide needed jobs, develop additional domestic energy production, and reduce our dependence on high cost insecure foreign oil.

Without this reinvestment rate our domestic discoveries will not be adequate to maintain production and this reinvestment rate cannot be maintained without sufficient cash flow from current operations. It is vitally important to the nation's energy security for producers to again see a period of stable tax policy without the seemingly annual tax changes threatening the already inadequate cash flow positions of most petroleum explorer-producers.

It was recognition of the vital role of the independents in exploration which resulted in the reduced windfall profit tax rates for independent producers on Tier 1 and Tier 2 oil. These provisions maximize incentives where they are most needed -- to stimulate exploration for new production in existing fields and to extend the economic life of marginal producing properties. It is a popular misconception that the reserves ultimately recoverable from known reservoirs is fixed and is not responsive to changes in policy. In fact, these reserves have great elasticity with regard to both price and tax policy. Continued drilling is required to both fully develop known fields and to establish their limits. Contrary to widely held misconceptions, the most readily available source of new daily production which can be realized in the shortest time is from development drilling in already known producing fields, i.e., so-called "old oil".

This drilling is no less expensive than exploratory drilling; it just has a lower element of risk. In addition to drilling, however, numerous other production expenses are required to maintain production and facilitate recovery at the maximum feasible levels.

By definition, "proved producing reserves" represent only the volume of hydrocarbons in place in the reservoir which can be recovered at a given price and using existing technology. The amount of recoverable reserves is increased not only by the function of higher prices delaying the convergence of natural declining production rates with escalating lifting costs, but also by allowing increased cash flow to support updated technology. It is only by recognizing the way in which existing reserves respond to changes in tax and pricing changes and their role in providing the producer a base of cash flow to support a drilling program that a rational energy policy can be established.

This fundamental need to delay the point at which marginal properties can no longer be economically maintained has been recognized by Congress since 1973 in the treatment of stripper well properties. All stripper well properties receive reduced windfall profit tax rates and stripper oil attributable to an independent producer's working interest is exempt after 1982. Independent producers have much lower overhead than the major companies. As family businesses and small partnerships, independents operate on a smaller scale and can more efficiently conduct these labor intensive operations. The incentives to stripper well properties have unquestionably had great impact. Since 1973 the number of producing stripper wells has increased from approximately 355,000 to 410,000 in 1981 while for the same period the total producing oil wells in the United

States has increased from 500,000 to 560,000 (Chart 10). Stripper wells have accounted for three-fourths of the increase in total U.S. oil wells. The source of this increase is just as telling. For years the number of stripper wells abandoned annually remained relatively steady or increased slightly with 13,500 stripper wells being abandoned in 1975. Since that time, however, the abandonment rate has steadily declined with only 6,600 wells abandoned in 1981.

# INCREASE IN STRIPPER WELLS ACCOUNT FOR MOST OF THE RISE IN TOTAL U.S. WELLS

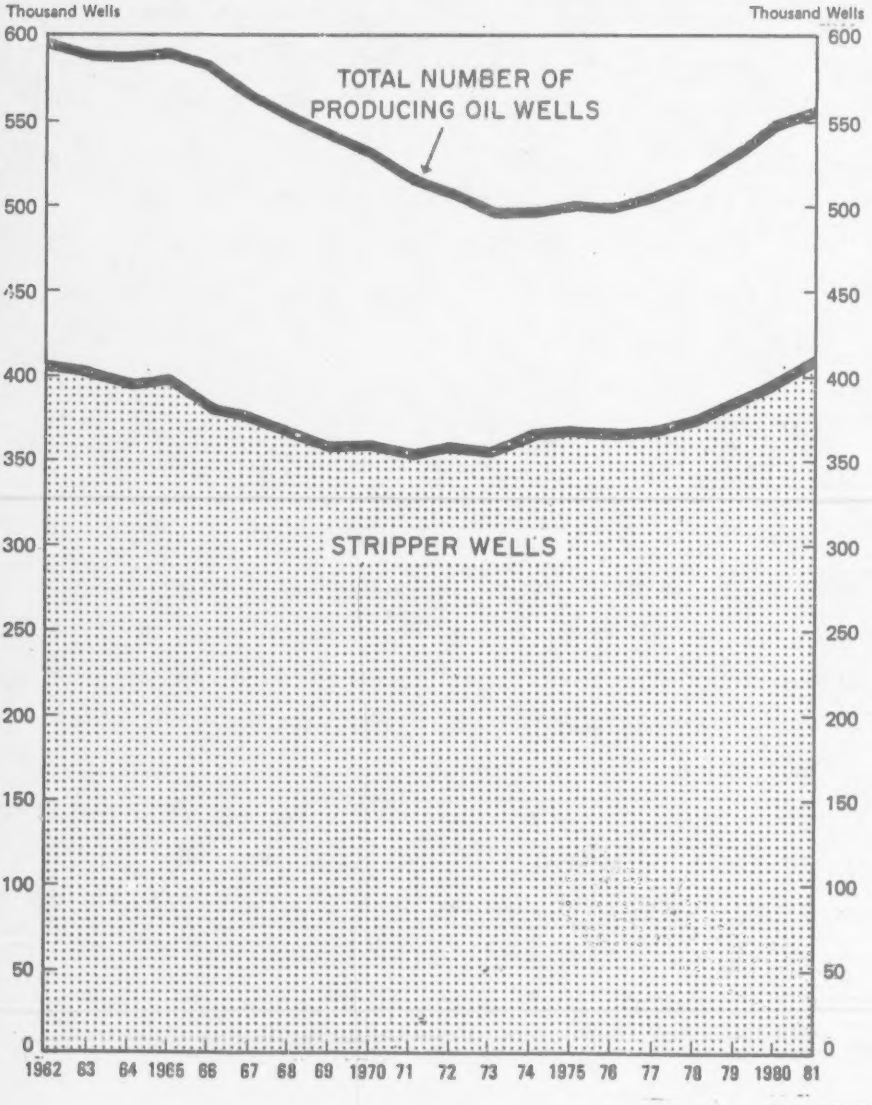


CHART 10

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Stripper well properties account for more than an eighth of the total U.S. production of crude oil. This represents 1.2 million barrels of crude oil daily and each barrel of stripper oil retained through decreased abandonments is one less barrel to import and one less barrel of new oil we need to discover. Stripper properties had been exempt from price controls since 1973 and thus received no economic benefit as a result of the decontrol of crude oil to justify a windfall profit tax. The imposition of the tax in 1980 had the same effect as a significant rollback in wellhead prices. The exemption alleviates this negative effect.

## V. PROPOSALS TO CHANGE TAX INCENTIVES ADD UNCERTAINTY OF TAX TREATMENT TO THE EXISTING CRUDE OIL PRICE UNCERTAINTY. THESE FACTORS EXACERBATE NEGATIVE TRENDS IN AN INDUSTRY ALREADY CRIPPLED BY RECESSION.

The problem in maintaining our nation's supplies of oil and gas is not one of resources; the oil and natural gas reserves are there, although most of the easily accessible resources have been developed. Nor is the problem one of resourcefulness; petroleum technology has reached a level of sophistication that can deal with the most complex geological structures and drilling locations.

The real problem facing producers is one of economics. Developing less and less accessible reserves will cost more and more money. The availability of capital, not the availability of acceptable drilling prospects, presents the greatest obstacle to exploratory drilling, and exploratory drilling has historically been the province of the independent producer.

Unlike an integrated oil company which has opportunities to profit from (and must make expenditures for) the refining of oil, transportation of products to the marketplace and retail sales of consumer products both in the U.S. and throughout the world, the independent producer can obtain his revenues (and make his expenditures) only from sales at the wellhead and only in the U.S. It is these revenues which must provide the capital for continued exploration, yet currently nearly half of the value of a barrel of oil disappears before it reaches the producer. On the average, fifteen percent of every barrel is returned to the mineral owner in the form of royalties and on newly leased acreage these royalty payments may be much higher. Seven percent of every barrel is paid to state and local governments in production and severance taxes, and these levies have also been steadily increasing. Finally, 23 percent of the barrel is paid out in windfall profit taxes, the largest and most complicated tax ever assessed against any industry (Chart 11).

## ONE BARREL OF U.S. OIL

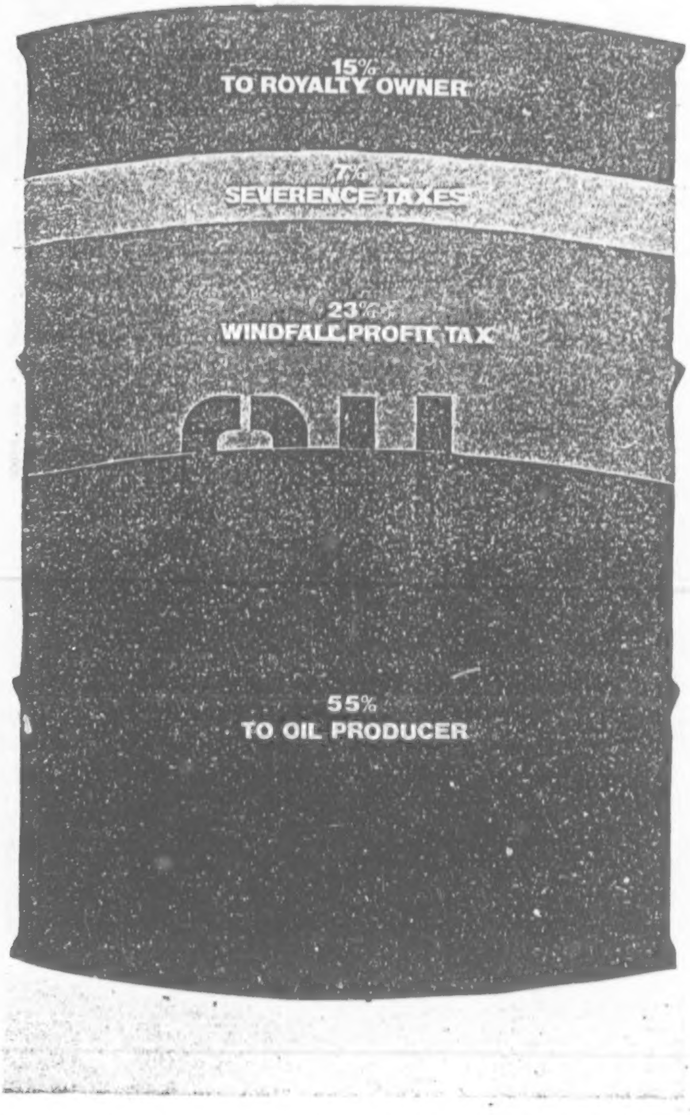

CHART 11

It is only from the remaining fifty-five percent of the barrel that the independent producer can pay the production, drilling and development expenditures, his income taxes, support his family and finance the next wildcat.

Exploration and drilling for oil and natural gas is a "current cash" business. Wildcat wells are not drilled with borrowed money -- the producer must use internally generated cash flow from current sales of oil and gas, augmented with funds from outside investors. Because overhead and operating costs of existing wells are essentially fixed and beyond his control, the only budget flexibility an independent has is in his exploration and drilling budget. Consequently, every dollar of income diverted to taxes reduces, by at least a dollar and usually more, expenditures for exploration and drilling.

Even development drilling (wells drilled to develop a field following initial discovery) require internally generated cash and investor funds. Generally, only after sufficient development has taken place so that the reserves are "proved up" and actual production from existing wells demonstrate the ability to repay a loan can borrowed funds be used for further development.

The sources of this cash flow have shrunken drastically in the last fourteen months. The decline in crude oil prices in response to the so-called "oil glut" induced by the world wide recession has reduced the wellhead value of crude oil production by $12 billion in 2 years. The inability to market natural gas has had a similarly dramatic impact on natural gas revenues. Investor funds raised by both publicly and privately offered drilling programs have fallen almost $4 billion from the record high of $9 billion in 1981. Yet even in the face of these dismal economics the industry as a whole still paid some $52 billion in state and local severance taxes, income taxes, windfall profit tax, and other payments to the federal government in 1982.

This precipitous fall in available funds has had a predictable impact on drilling activity. By any measure the industry is in the midst of a deep and severe recession. The number of active drilling rigs has fallen from its peak of 4,530 in 1981 to only 1,840 in April 1984 (Chart 12). This results in the lowest number of operating rigs since 1977. Just as an increase in drilling activity spreads benefits throughout the economy, the impact of idle rigs is only the tip of an iceberg of unemployment.

## U.S. DRILLING

### Active Rotary Rigs Decline

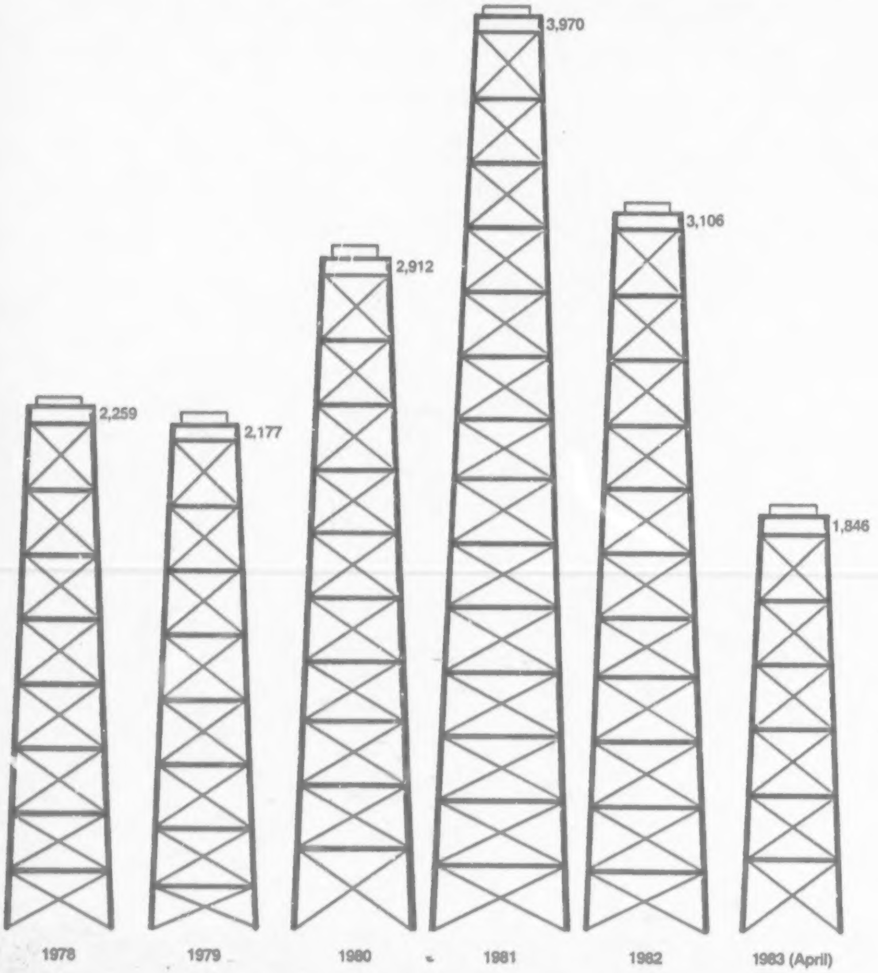

CHART 12

Presently there are 40,350 unemployed drilling crewmen and at least that many more in oil field service industries. Sound tax policy would prohibit the levying of additional punitive taxes against any industry in the crippled state of the petroleum industry today.

Just to maintain current levels of domestic production 570,000 new wells must be drilled through 1990. In evaluating the magnitude of this task, a recent analysis by Petroleum Information Corp. reaches some interesting conclusions. For the period 1974 through 1980 the average number of wells completed by each active operator has remained relatively constant, fluctuating within the range of 6.5 and 7.2 wells annually (Chart 13).

## AS OPERATORS INCREASE, AVERAGE WELLS COMPLETED BY OPERATORS REMAINS CONSTANT

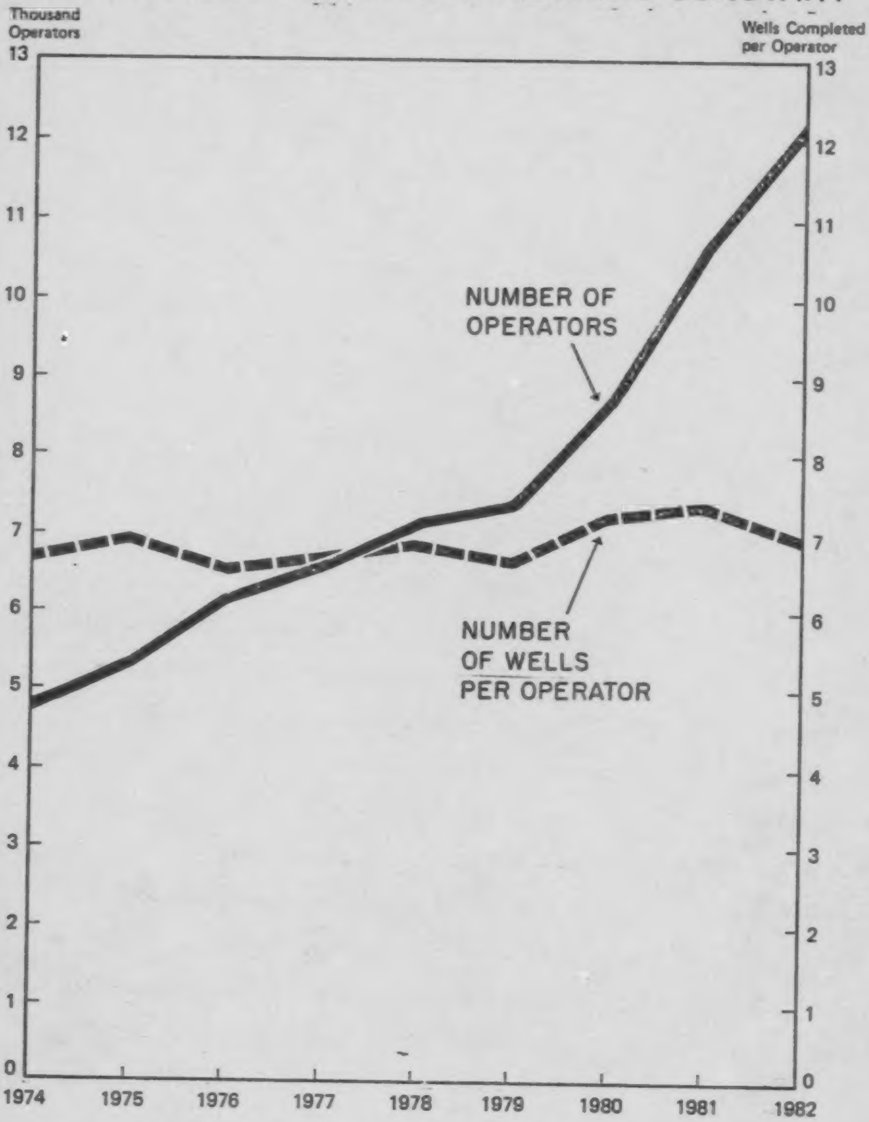

CHART 13

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Total well completions, however, increased from 32,000 in 1974 to the 1982 record of more than 85,000 as the number of operators increased. Maintaining our domestic production is not just a matter of increasing the expenditures of our existing producers. We must also expand the number of operators. It is the formation of new companies and the ease of entry for individuals and partnerships into the business that is necessary for sustained growth. It is these new entrants and emerging enterprises for whom the existing tax incentives are both the most necessary and the most beneficial. Without these incentives, the industry will never attract the capital to achieve energy security.

## CONCLUSION

As we all know, this country developed and maintained energy supplies in excess of its needs for more than a century. This did not occur because providence favored America over other nations with petroleum deposits. It did not happen because we -- as a people -- possessed a keener nose for oil and gas than others. It happened because only in America are individuals permitted rights which are the essence of private enterprise -- the rights to own, to sell, to buy, to explore and to produce petroleum fuels. In every other nation those rights are reserved by and for governments

Now, these unique rights existing only in America guarantee nothing to anyone. In the cumulative experiences of tens of thousands of explorers, successes have ranged from abject failure to extraordinary discoveries. It has been the possibility of extraordinary success that has lured so many, for so long, to the search for oil and gas. Should that possibility ever be lost or denied, our energy and economic futures will be foredoomed.

The energy future of America literally will be secure or insecure based on public and political understanding of two very simple facts: (1) Nobody is excluded from the oil business, but (2) nobody has to be in the oil business. With encouragement to help meet this country's future energy needs, independent explorer-producers will continue to fulfill the same vital role they filled in making the world's leading energy producer of a country that could have never realized such achievement under any but a free economic system that rewarded the risks and successes of private enterprise.

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Comment on Statement of Robert S. McIntyre, Director of Federal Tax Policy, Citizens for Tax Justice to Subcommittee on Oversight, House Ways and Means, May 6, 1983.

The statement of Mr. McIntyre contains a number of remarks which are incomplete and misleading. Great emphasis is placed on a review of the taxes paid for 1982 by nine "randomly" chosen independent oil and gas companies for 1982. 1/ Although reporting $476 million in pre-tax income to their shareholders, the nine companies paid no net federal income tax for the year. This is alleged to be a "fascinating, concrete insight" into the tax benefits received by independent producers and evidence that one industry "not paying its fair share of income taxes is the independent producers."

However, the fallacy of this conclusion is readily apparent upon review of more complete financial information of these companies. During 1982 the nine companies had gross revenue from oil and gas operations of $2 billion, but expended in excess of $2.9 billion in exploration, drilling, and production activities, excluding substantial amounts expended for the acquisition of proven properties with existing production. This $2.9 billion in investments was in addition to payments to the U.S. Treasury of more than $150 million in so-called "windfall profit" taxes.

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1/ See attached list.

When all of the information is analyzed, the logical conclusion is not that this "random" group demonstrate an abuse of "tax loopholes" but instead they are an illustration of the effectiveness of incentives adopted to encourage exploration and development of crude oil and natural gas. When windfall profit taxes are included there can really be no question that the companies are contributing their "fair share" to the support of our government.

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Comment on Report Effective Federal Tax Rates on Income from Oil and Gas Extraction by Jane G. Gravelle, April 13, 1983, Congressional Research Service.

The statement of Jane Gravelle attempts to quantify the effective federal tax rate on new oil and gas investments depending upon the classification of the producer. The stated conclusion is that oil and gas investments are taxed at far lower rates than other forms of investment.

This conclusion, however, results from two critical assumptions which do not reflect the eocnomic reality of such investments. Of foremost importance is the erroneous inclusion of dry hole and abandonment loss costs in the effective tax rate model. Amounts expended on unsuccessful ventures constitute 52 percent of the investment in oil and gas reserves in the investment profile employed. These expenditures yield no economic benefit to the producer, resulting instead in significant after tax economic losses. The federal tax system does not impose tax on such losses incurred in this or any other industry. The inclusion of dry hole and abandonment costs in the effective tax rate model results in a severe distortion of the tax rate. On average, four out of five exploratory wells are dry holes, yet each new venture is statistically independent of the last. Drilling four dry holes does not increase the chances that the next well will be successful.

The tax rate model is also sensitive to the relationship of the tax treatment of investment in relation to the actual economic life of the acquired asset. For investments in oil and gas reserves the model uses an economic depreciation rate of .0663. The rate, which is roughly equivalent to a life of 15 years, greatly overstates the life of a typical producing field and as a result overstates the benefits of the option to currently expense intangible drilling costs. In the aggregate, 8 years is the average life of productive oil and gas fields.

The deduction of IDC and the provision for percentage depletion provide useful, efficient and necessary incentives to stimulate petroleum investments. This study, however, greatly distorts the impact of these provisions relative to alternative forms of investment. As stated by J. Gregory Ballentine, Deputy Assistant Secretary of Treasury in testimony before the subcommittee:

> ". . .it can no longer be asserted as a general proposition that the tax system favors investment in domestic oil and gas production."

The analysis fails tc account for the risk factors. Investment in exploration and development of oil and natural gas carries an assured high failure rate. Competing potential investments often have an equal rate of return on successful ventures without a comparable risk.

In most instances, decisions about specific investments are based on the marginal costs of revenues involved, not on industry averages. Thus, the economic incentive value of percentage depletion and current expensing of intangibles is their impact on the marginal investment in leading-edge exploratory drilling and enhanced recovery projects intended to increase or maintain production of older declining wells. Failure to account for this reality is another serious flaw in the analysis.

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Comment on Statements of Professors Robert Conrad, Walter Mead, and
Arthur Wright to Subcommittee on Oversight, House Ways and Means,
May 5, 1983

The testimonies of Professors Robert Conrad, Walter Mead and Arthur Wright have several common arguments pertaining to economic efficiency, energy security and the effects of the petroleum industry's tax incentives. Each subject deserves examination.

On grounds of economic efficiency, it is contended that percentage depletion and the current expensing of intangible drilling costs create an incentive for capital to flow to those firms favored by the tax provisions. As the theory goes, scarce resources are thereby "misallocated" which leads to inequities and welfare losses for society as a whole.

It is important to describe just what is meant by "economic efficiency" and how it relates to the real world of the oil business. Given competitive conditions, the economic system allocates society's scarce resources (i.e., land, labor and capital) in such a way that certain technical requirements necessary for efficiency are met. In theory, the action of market forces will lead to an efficient resource mix, assuming no externalities or market imperfections. On an aggregate level, economic efficiency means that it is impossible to change prices or output to make someone better off without simultaneously making someone else worse off.

Tax neutrality is one economic component of this perfect scenario. To be neutral, a tax must result in a resource allocation identical to that which would prevail if no such tax had ever been imposed. In other words, none of the behavioral variables in economic decision-making are altered by a neutral tax.

In contrast to these theoretical constructs, consider the oil business, which is far from such a textbook case. Although it is generally agreed (even by the three professors) that the oil industry is competitive, market externalities and distortions exist. First through indirect controls on less expensive foreign produced oil and then with direct wellhead price and allocation control of both crude oil and natural gas, government policies have dictated the market price from the mid-1950's until the present. These policies artificially increase demand while depressing domestic exploration and production.

In addititon, there are barriers to an efficient clearing of the oil market. There is imperfect access to capital markets in this highly captital-intensive industry as tax neutrality does not exist with respect to alternative investments. There are also the substantial risks of drilling dry holes. Finally, the market price of domestic crude oil is primarily determined through unpredictable economic and political forces in the world market beyond the control of the producer.

For all of these reasons, it is meaningless to analyze the oil industry's tax structure in terms of economic efficiency models. The efficacy of the tax incentives does not depend on neutrality or non-neutrality. Rather it depends upon the relevant public policy goals and alternative means of achieving them. In the case of the oil industry, the dominant rationale for tax incentives has been national energy security. Nowhere does there appear any evidence of a more cost-effective method of attaining this political objective than the present tax system.

Looking more closely at the issue of national security, Professor Wright asserts that it should be achieved by the stockpile program and retaining domestic reserves rather than by encouraging production. This assertion has at least three major flaws. First, if large volumes of oil are imported, both the U.S. and world economies would be impacted through an even larger trade deficit. Second, even if this were not so, as a practical matter, the cost to government through "stockpiling" foreign oil adequate for security needs surely would exceed the costs of incentives for increasing domestic supplies through tax provisions. Third, in the event of a major supply disruption, no industry can respond to an emergency when its critical infrastructure has been allowed to deteriorate. Without rigs, geologists and operating staffs in place, producing capacity cannot be replaced for years. The lesson of the last fifteen years should not be forgotten.

More specifically, consider the difference between wartime and peacetime energy policy needs. In peacetime it is important to develop a pool of extra proved reserves in order to avoid being vulnerable to some oil import disruption. By contrast, the focus of wartime policy generally shifts to the continued flow of crude oil production during the conflict. If reserves drop below a threshold point, it becomes necessary to direct resources into finding and developing new reserves rather than trying to maintain required output levels from rapidly dwindling reserves. Wartime energy policy would thus be aimed at discovering new reserves as well as maintaining existing production -- a costly diversion during war.

Contrary to Professor Wright's view, the primary peacetime goal of public policy should be to encourage the oil industry to widen its base of proved reserves in order to avoid a costly strain on (or worse, inability to sustain) productive capacity during any national emergency.

Turning to the actual effects of the tax incentives, all three witnesses mention that large firms are induced to fragment into smaller units or at the very least, that smaller firms will be able to capture a larger share of the market relative to large firms. There is no evidence to suggest that these structural changes are occurring. The relative size of large producers in itself prohibits any downsizing. The benefits of size in access to captial markets and economies of scale preclude any rational reduction in their size. At the margin, there are only a very few firms who are in a position to feasibly opt for either independent or major status. This hardly constitutes an industry restructuring or fragmenting. In any event to the extent such restructuring occurs, competition is increased which both adds to supply and lowers price to consumers.

Finally, Professor Conrad makes the point that current tax incentives tend to lower the market value of crude oil further below its true social value. Earlier in his analysis, however, he states that the impact of the tax differential is "limited by the fact that the market price of crude oil is determined in world markets." It has been shown that the oil industry's tax provisions result in significant economic effects on proved reserves, output and investment but no such relationship has been proven with prices where they are market-determined.

Professor Mead also attributes the low petroleum product prices up until the early 1970's to the oil industry's tax concessions. During that period, however, the domestic price of crude oil was determined by world market forces. In fact, government used the oil import "valve" as a "damper" that held U.S. prices progressively below replacement costs for almost two decades. With an excess of foreign oil which can be produced at much lower cost than U.S. oil, prices for domestic production were held artificially low. This led to dismantling our domestic exploration -- production industry and ultimate vulnerability to blackmail through disruption of supplies of "cheap" foreign oil.

In summary, economic theory must take into account political factors associated with petroleum in the national energy picture. Economic efficiency and tax neutrality analyses are misleading because they ignore the public policy goals for which tax provisions were originally instituted. Energy security needs require the maintenance of sufficient productive capacity in addition to as much proved reserves as possible. Eliminating tax incentives in favor of a stockpiling program alone would cripple the already ailing industry to the point of jeopardizing U.S. energy security.

May 1983

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Comment on Statement of Alice Rivlin. Director, and Analysis of Special Tax Provisions Affecting Independent Oil and Gas Producers by Robert Lucke, Staff, Congressional Budget Office to Subcommittee on Oversight, House Ways and Means, May 5, 1983.

The CBO has included in its statements an estimate of the impact of the differential tax treatment of various producers determined by using three hypothetical oil properties. These examples attempt to provide a quantification of the differences in tax treatment between integrated corporations, independent corporations and a proprietorship or partnership producing oil from wells which have varying windfall profit tax classifications using a discounted cash flow analysis. These examples are misleading in their method of presentation. In the determination of the tax rate the examples include a tax on the shareholders of both the integrated and independent corporations. This tax is in addition to the regular corporate tax and is computed as if the corporation distributed 40 percent of its cash flow and the remaining amount is retained. A one year distribution of 40 percent of cash flow is virtually unheard of in the petroleum industry where expenditures for exploration, development, and production usually exceed gross income. It is then assumed that the shareholder realizes a capital gain on the remainder in four years. While it is true that these taxes, and the double taxation of corporate profits exist, they are part of our tax system for all types of enterprises. They are not unique to the oil and gas industry and of no value in addressing differences in tax treatment between integrated and independent producers.

The examples also contain other significant problems which limit their usefulness. The cash flow model is constructed backwards, i.e., it assumes the same revenue and rate of return for each producer. Then in order to account for the difference in tax treatment it allocates to the "bonus payment" (acquisition cost) for the original undeveloped property an assumed investment for each producer equal to the full difference in tax treatment. The model then compares effective tax rates on these properties having different investments but equal rates of return. The result is that the integrated company has a lower investment and thus lower depletion deductions, resulting in a correspondingly higher tax burden. In other words, by anticipating a higher tax burden in the investment model, higher taxes are assured.

Similarly, the structure distorts the tax on the partnership or proprietorship in the opposite direction. An entity subject only to personal tax rates is assumed to have a higher investment in the property. Although percentage depletion interacts with this basis to provide only marginally higher depletion deductions, the excess basis eliminates any impact of the minimum tax.

As a result, these examples should not be considered reflective of either normal petroleum industry activity or the impact of the existing tax differentials.

The CBO has also provided the subcommittee with estimates of the revenue effects of changing the tax provisions, the most significant of which are the current expensing of intangible drilling costs and percentage depletion for independent producers. In evaluating the revenue effects each item is treated separately without consideration of the manner in which they interact. Capitalized intangible drilling costs are recovered through depletion and any increase in the basis for cost depletion reduces the beneficial impact of percentage depletion. Therefore, if both provisions are changed at the same time the combined revenue increase will be far less than the sum of the revenue increases shown by the CBO.

The most serious flaw of these revenue estimates, however, is the methodology they employ, which ignores the changes in economic activity which result from the provisions. The tax provisions were, of course, adopted to provide incentives to increase exploration and development yet it is the benefits from this activity that are not included in the revenue estimates. It should be fundamentally clear that these provisions serve to increase activity in the domestic petroleum industry and the economic benefits of this incremental activity are substantial.

A study entitled The Economic Impacts of the Intangible Drilling and Development Costs (IDC) Tax Provision on the Petroleum Industry prepared by Price Waterhouse & Company for the American Petroleum Institute has been submitted to the subcommittee for the record. This study concludes that for corporations for every dollar in income tax forgone due to the IDC deduction, the Treasury receives $1.25 to $3.24 in additional income tax and windfall profit tax revenues, due to the stimulus IDC provides to drilling activity. The behavioral responses for individuals are more difficult to assess, but the analysis suggests that individuals may be more responsive than corporations. For individuals, the ratio of increased federal tax revenues to each dollar of tax forgone range from $1.24 to $4.52.

The conclusions in the study result from a comparison of (1) currently expensing IDC with (2) capitalizing such costs subject to five year ACRS and the investment tax credit. The study concludes that ACRS treatment would reduce the after tax rate of return on a model investment from 32.89 percent to 28.40 percent. (Although this return appears high it does not include royalties or the costs incurred in unsuccessful wells.) If the model investment is adapted to include percentage depletion it is our estimate that the rate of return would increase from 32.89 percent to approximately 37.3 percent. There is no reason to assume that when producers subject to percentage depletion are included that the incremental drilling response would not equal or exceed that for intangible drilling costs.

May 1983

Mr. **Anthony**. Thank you very much for a very detailed and comprehensive statement.

Mr. Campbell, do you have questions?

Mr. **Campbell**. Thank you, Mr. Chairman.

Even if it is admitted that there is a need for providing incentives for exploration and drilling for oil and gas, why is it necessary to have both percentage depletion allowances and current expensing of intangible drilling costs?

Mr. **Jansma**. OK. That is a very good question.

Percentage depletion is designed to return capital. The percentage depletion is a recognition of the fact that the oil and gas industry is a unique industry, as are other extracting industries. As I produce my oil and gas wells, the assets that I have disappear. When I am finished, I have nothing left.

Percentage depletion came about in the 1920's when there was a realization that every drop of oil that came out of a well represented a return of both income, to be taxed, and capital, to be put back in the ground looking for new assets. And so percentage depletion is necessary to return capital to cover the dry holes that I drill which, even though I can write them off, I still have paid at least 50 percent out of my back pocket, and I have to have the capital to reinvest for additional assets.

Intangible drilling costs, on the other hand, you had some testimony earlier today by the Treasury I believe that indicated under the new ACR proposals—not proposals, they are part of our law—there is very little difference between intangible drilling cost writeoff and the ACRS. This is true. However, the one thing that we have to realize is on a macroeconomic basis in the Nation, where we can say there is very little difference; on a microeconomic basis, when I go to a person to put up money in drilling a well, the fact that they have to capitalize rather than presently writeoff means a whole lot to that individual. Intangible drilling costs are a very important provision that the industry needs for raising outside capital.

Mr. **Campbell**. You have mentioned raising outside capital. You mentioned covering the cost of drilling the dry holes.

What percentage of your effort turns out to be dry holes?

Mr. **Jansma**. Eighty percent of all exploratory wells are dry holes.

Mr. **Campbell**. How difficult is it to attract capital that is necessary to explore and drill?

Mr. **Jansma**. It is extremely difficult.

One thing I would like to mention, however, is that in my experience, I do not see people coming into this industry just with the idea of saying I need a tax writeoff. Everyone that I approach regarding investing in the industry wants to have an economic return on his investment. Today, with the tax laws changed where a person can buy a building and write it off in a much faster time, the oil and gas industry has a harder time competing for the pool of capital.

Mr. **Campbell**. What you are talking about is a reasonable return on investment?

Mr. **Jansma**. That is right.

Mr. CAMPBELL. If we were to change some of the laws we might remove the possibility of a reasonable return on investment, is that correct?

Mr. JANSMA. That is correct.

Mr. CAMPBELL. You also made another statement that I found very interesting. The independent producers are spending 108 percent of their gross revenue. A lot of people are going to find that hard to understand. I really would like to have a little more explanation of it.

Did you mean net revenue, or gross revenue, or was it a misstatement or what?

Mr. JANSMA. No, I meant gross revenue. The significant—by the way, those numbers come from the U.S. Census Bureau, so they are numbers that we have received from the U.S. Government. The numbers indicate that, frankly, the independent producer is doing a lot of hustling, reinvesting the money he has gotten. But you did not hear wrong. It was 108 percent of gross revenue.

By the way, that does include borrowed funds that I borrowed on existing production to turn around and put into new drilling.

Mr. CAMPBELL. In your testimony you said there are about 15,000 independent producers. We have had earlier testimony that there are about 240 corporations or companies that are involved. That is in publicly held groups. But of the 15,000 independent producers, the IRS estimates there are about ½ to 1 million taxpayers who claim tax treatment as independent producers. How do you explain that type of discrepancy?

Does that cover investors, or what does that cover?

Mr. JANSMA. Basically it covers investors. What I mean to say is, when we say there are 15,000 independents in the United States, I am referring specifically to people, men and women, who are actively involved in drilling and producing and searching for oil and gas. I myself will go to outside investors and will receive money from them for investing.

Under the Internal Revenue Service Code, any person with an economic interest in oil and gas is a producer, and then the question becomes, is he a major producer or an independent? And you understand, of course, how an independent is defined that way.

So all of my investors file taxes, I hope, and are termed independent producers by the IRS definition. But we refer to independents as the 15,000 people active in the business.

Mr. CAMPBELL. You answered one of my other questions a while ago, about the amortization of drilling costs on the macro and micro level.

Let me ask you this: The independents are able to take the percentage depletion today on 1,000 barrels of production. Notwithstanding that, and notwithstanding the fact that the price of oil has declined, at $28 a barrel that still comes out to about $10 million a year. With 15,000 independent producers, that comes out to be an astronomical figure. How can we justify that type of a loss in revenues?

Is it justified by your testimony that we have to have that $150 million investment going back into the industry to keep it going? Do we get $150 million worth of benefits?

Mr. **Jansma**. As a practical matter, our numbers indicate that there are between 200 and 250 producers who would fall in that area of 1,000 barrels per day. All of the rest of the independent producers would be far below that number.

As a matter of fact, if you take just the gross numbers and divide them up, you will find that each independent producer on an average would only have about 15 or 20 wells. That would be total.

Second, you would notice that the average production per well is about 3 or 4 barrels per well.

So the numbers that are cited there are assuming, of course, that everyone is in that category, when in fact the vast majority are small producing companies and individuals.

Mr. **Campbell**. My time is just about up.

Let me ask you one more.

One thing that is a bit of a contradiction in your testimony is that some of the data that you have presented, you pointed out there has been a very steep decline over the past 19 months in the number of drilling rigs that are operating. At the same time in 1982 the industry set a record for the number of wells completed.

Now, how do you reconcile those two?

Mr. **Jansma**. OK. Michigan—I will tell you how it is done in Michigan.

You keep track of the number of drilling rigs via the Hughes tool report or the Reed report, where they are actually out in the field counting the rigs. However, the number of well completions are kept track of by the States. When I have drilled a well in November 1981, and I get a completion rig and don't get it completed until January or so, the well is counted as a discovery when I file the report with the State. So the bottom line is that there is basically a lag problem in getting the data.

Mr. **Campbell**. If it is a lag problem in getting the data, does that mean we have the possibility, under the current law, of seeing more drilling rigs going back into use? Are we still on a downward trend?

Mr. **Jansma**. It is difficult to say where down would get to. But my reaction would be that I would feel we are at the bottom or very near it, and we will see an increase in drilling rates again.

Mr. **Scoggins**. If I might amplify slightly on this question about the lag, there is about a 6-months difference in the reporting of the number of rigs operating and the number of wells actually completed. And the reverse of what we have seen, where we have had a declining rig count, and yet an increasing well completion, about a 6-month delay. So, as the rig count starts back up again, as we come out of this slump, assuming that we do, you will see the number of well completions continues on a downward trend for probably another 6 months. It is simply a statistical phenomenon.

Mr. **Campbell**. Thank you.

Chairman **Rangel**. Mr. Pickle?

Mr. **Pickle**. I thank the gentlemen for their testimony.

I am sorry that the full committee is not here to see these charts, and to know the facts represented by these charts. I think they would have a different view of the problems and the challenges we have.

The fact that the drilling now is less than half what it has been a year or two ago, when you consider out of every barrel of oil nearly half of it is taken away before the producer gets a penny of it—45 percent of it with 15 percent to the royalty owner, the next 7 to the severance tax, and 23 percent to windfall profit tax. Consider also, in spite of all that, he reinvests, not just 100 but 108 percent. If you look at where the money goes when you receive it—cement, well servicing, transportation—you realize the enormous risk, and a lot of it is raked off before the producer ever realizes a profit.

I want to ask you: What is your profit return? The thing I am impressed with most of all is your statement that even if we assume a 2 percent normal growth, and assuming that we keep the import level at approximately 30 percent, we have to have 11.4 million barrels of domestic oil by 1992.

Talking from a base of 8.7 million barrels per day, which we have now, up to 11, would mean you have to drill 890,000 new wells just to meet minimum levels.

Now, that is something for us to ponder.

Even if everything was perfect, you would have a hard time maintaining that schedule. But with all the difficulties we are facing, under restrictions, it would make it impossible for us to achieve those goals. I am confident the committee is not going to take action here that makes it impossible for us to have our supply of oil and/or gas.

Someone recently told me over half the gas wells that we will need to supply the country's gas requirement in the next 5 years have not been drilled yet. We just can't assume they are going to be there when we turn on the faucet.

I think these things are significant, these charts. I am going to try to get them summarized to give to all the members.

Let me ask you two or three questions.

You stated that the problem in maintaining our supplies—you said it was not just one of resources, it is not just one of technology, because we have the technology—what we really have is a problem of economics.

Do you want to enlarge on that any further? Are you saying it doesn't pay off, you cannot risk it?

What do you mean?

Mr. JANSMA. What I meant to get at is that the industry has had three major things hit it in the last several months. Crude oil has dropped 25 percent. That has pulled $12 billion out of the domestic petroleum industry.

I also mentioned in my testimony that since our operating costs are basically fixed, that increase in taxes results in less drilling. Frankly, less income to my company of gross oil and gas revenues results in less drilling, because the first place that I can cut is drilling. I have to still operate my existing wells.

So, what I was trying to get at,. economically we were hit with lower oil prices, we are hit with right now an inability to sell natural gas. And then, third, going out into the investing public and asking for money, we have not received the funds there that we would normally get.

Mr. PICKLE. You are saying, in effect, a capital crunch is particularly severe on the independent producers at this time?

Mr. **Jansma**. That is right.

Mr. **Unsell**. I would like another element in that picture.

The Wall Street Journal last week, as you know, had a lengthy article on the unfortunate problem that the First National Bank of Midland has had. And within that article was a statistic that was new to me, but it stated that 425 banks in the southwestern part of the United States have had severe difficulties because of bad energy loans and the energy slump. When you affect financial institutions to that degree, you develop a great reluctance in the financial community to entertain the idea of financing drilling programs. And this is happening.

I have talked to a great many independent producers whose banker won't talk to them any more. And this is another element—capital resources, that we have taken for granted for many years, have just dried up.

Mr. **Pickle**. The current expensing of the intangible drilling cost is applicable to wells. Does this encourage people to simply do more drilling in existing producing fields and divert attention away from exploring for wells where it is really needed?

Is that an accurate appraisal of what happens?

Mr. **Jansma**. No; that presupposes of course that drilling in existing fields is far, far less risky . Well, in a way it definitely is. However, the thing that we have to realize is that when you drill the first discovery well, all you have is one point on the map. You don't know exactly whether that field goes north, south, east, or west. And in Michigan we don't know whether that field has permeability in it.

We may have just one well in that reservoir. So, the drilling of development wells, though less risky, has a fair degree of risk, and the IDC's are necessary for those wells as well as the exploratory wells.

Mr. **Pickle**. There was testimony this morning with regard to expensing IDC's—that other investments may in fact be more attractive because of the ACRS and the ITC. So we are not getting big breaks in expensing. You could do better in other fields today.

Mr. **Jansma**. That is right.

Mr. **Pickle**. Now, I want to put on record one more figure. I understand the number of drilling rigs operating seems to have been sharply declining for the past 18 months. According to the figures I have, the industry has set a record number of wells completed. In other words, there has been a decline in the number of rigs used, and yet the successful completion of the wells has increased.

Is there a contradiction to that?

Mr. **Jansma**. No; that gets back to the lag between the way the wells are reported and the way the drilling rigs are reported. It is a matter of time.

Mr. **Pickle**. Thank you, Mr. Chairman.

Chairman **Rangel**. I want to apologize for not being here for your initial testimony. I want to thank you. There will be other questions.

Not coming from an oil-producing State, it was difficult for me to understand the plight of the independents. Certainly, you have had some dramatic testimony here today. However, it is a very expensive preferential tax treatment that we are giving to the independents as opposed to the majors, or under some type of uniform system.

We don't know, and I guess you don't have information for us to determine truly who is this independent and how much return do they get on their investment. You did describe it as being a person with only 15 to 20 wells, and 3 to 4 barrels a day. But some of the people have described the uniqueness of independent producers as those in need of capital, telling us we should have a lower tax rate, that you want to prevent monopolies, that we have to have more dependence on domestic oil.

Wouldn't it be a heck of a lot easier just to raise the special lower tax rate and have one tax, take that $3 billion in revenue gain and decide who needs it. For those independent fellows that need some Federal assistance, give it to them in grants in assistance, rather than have us manipulating a tax system where we cannot even determine who really needs this type of tax incentive and who is merely taking advantage of a tax benefit we provided?

You have to be the first to recognize that the oil industry generally, independents specifically, are considered to receive preferential treatment by this tax-writing committee. And it is difficult for those of us who have non-oil producing communities to explain why it's money well spent.

Why would you not just want the Federal Government to go and provide the grants rather than for us to be in partnership with you the way we are with the tax code?

Mr. **Jansma**. I think one of the key things to me is what is the ultimate effect on the consumer. That is my taskmaster, when the chips are down. And by having some of these benefits, you have to look at what were the results of the benefits. And the independent petroleum segment of the industry has found such a substantial amount of crude oil and natural gas in the last years and has endeavored to find it in the domestic United States. The effect on the consumer for people in my city who cannot afford energy is that we today have lower energy costs because of the fact that there has been this industry trying to find it the way we have done it.

Chairman **Rangel**. Wouldn't you have done it without this?

With the price of oil declining as it has for the past 1½ years, even when we had the tax advantages to which you make reference, people have been going broke in the industry by the dozens.

Mr. **Jansma**. We have stacked over half of our drilling rigs. We are no longer finding as much oil as we are using.

Can you imagine what a catastrophe we would have had if we had this price decline and did not have the tax provisions that have been available during this period of time?

As one of the earlier witnesses testified, if you took these provisions out of the tax code at the present time, it would have the same effect as reducing the price of oil to the producer by, he said, from $6 to $12, and his best guess was $10 a barrel——

Chairman **Rangel**. What if we substituted the preferential tax treatment with a grant like we do other industries that may be in trouble. When the price on something goes down, it means that demand has gone down. The oil industry is a great industry we have and certainly it is one that our very national security depends on. So, I am not saying that we should just let the free marketplace work its will, which the President says should happen in so many other industries.

I am for giving preferential treatment to those industries which our national security depends on.

My question to you is: Why should we use the tax system to do it? Why can't we determine which of the independents need help, and how much incentive is necessary, rather than have it appear as though we may be giving incentives to some people who are independents for the purposes of the statute, the tax law, but don't need any help, and they will continue to reinvest and make pretty healthy profits and not pay comparable taxes on that money? We're talking about ½ to 1 million taxpayers who qualify for independent producer tax breaks.

Mr. SCOGGINS. One reason for using the tax provisions to do it rather than by Government grants is because it is a lot more cost efficient to do it through tax provisions than through grants, and certainly it is a lot more efficient doing it this way than by giving some sort of price subsidy.

For each dollar of percentage depletion that you take away from a producer under the present system, it requires $2.85 of additional selling price to give him the same cash flow.

That is how efficient it is to do it the way we are presently doing it.

Chairman RANGEL. Any other questions?

Mr. THOMAS. Mr. Chairman?

Chairman RANGEL. Mr. Thomas.

Mr. THOMAS. Thank you, Mr. Chairman.

I want to compliment myself on my great restraint in not biting through my pipe on hearing of some of the comments that were just made.

First of all, I am not so sure that the tax-writing committee believes that what is currently in the tax law produces an unfair relationship or even unnecessary relationships, and I am not so sure this subcommittee does.

I thought that was in part the purpose of the hearings.

I think that is yet to be determined.

Second, I really would like to see what would happen if the Government got in the oil business. It would be like Government activities in a number of other areas. We would wind up with less of the product and a higher price.

One of the reasons that we are talking about the number of rigs that are not in use at this time is because there was some movement toward a free marketplace.

The price was artificial. The price will settle out, and the tax code is an excellent incentive device, though one is looking for Government grants in this area, and one of the surest ways to kill incentive and desire is to assume that the Government is going to take care of you.

I certainly hope that is not the direction that the subcommittee is directing itself, and it certainly wasn't an understanding from the gentleman from Texas in earlier statements supported by this gentleman from California.

Let me say also that the State of New York produces 841 barrels a day. The State of New Jersey is an oil producer.

But we talked about the price of oil. When you talk about the average price of oil—Mr. Jansma indicated it was like $28 a barrel. It fluctuates, obviously, but in looking at your front cover, you deal obviously in a number of States in your organization.

When you talked about the average price of oil, it varies greatly from State to State. I have got some dollar prices from California, February 1983. This is the Union Oil price schedule. There are a number of other companies here.

The highest price listed for any is $26 a barrel. That is 37, pretty sweet stuff, I imagine. It ranges down to 21, 17, 20, 16.40, or Kent Canyon at 11 gravity.

Isn't it quite true that what is considered an average price of oil certainly isn't average and would be above the absolute market price for very significant oil areas in the United States?

Mr. **Jansma**. That is exactly right.

Mr. **Thomas**. And to the degree you are below that average price, and costs are not significantly cheaper, or in some instances they may be higher, depending upon the type of oil you are producing, that the problems that you indicated face independent producers are only greater problems in the various areas.

Mr. **Jansma**. That is correct.

Mr. **Scoggins**. Mr. Thomas, if I might inject there, in California in particular, as well as some other areas, not only does the oil receive a much lower price, it also usually costs quite a bit more to produce, which significantly compounds the problem for a producer.

Mr. **Thomas**. In addition to that, through the wisdom of the Congress, we are unable to move Alaskan oil to markets where it might be economic. In fact, we are forced to bring it into an area which is oil rich in the first place, so we compound the problem by having Alaskan oil being required to ship to the United States as well.

I guess part of the problem is that we have a large number of members of the House who just don't understand the oil industry.

I am grateful for your presentation.

One of your problems, I guess, is that you just drill too many dry holes. You ought to watch that.

On your chart, in terms of the ancillary support, the congressional delegation from Oklahoma indicated that this was a significant factor. Now, energy production, oil and gas production, are basic industries. You have in your presentation an example of a well in Louisiana and you have all of the various companies that are in support of that, with the number of employees.

I might suggest to you that you might have a meaningful communication device if you will copy to a degree what agriculture does in terms of the typical farmer and how many Americans that typical farmer feeds—64, 72, whatever the number is now, it is going up because of economies of scale—and rather than talk about statewide or industrywide, you might take your 15,000 independent producers and indicate just how many people and their families are directly supported by each producer.

I don't know if you can produce that material now, but I think it might be useful. I think it would underscore the very basic nature of the industry.

It produces an invaluable commodity, but it also, as was graphically indicated by the testimony of the Oklahoma delegation, is very significant in terms of jobs and employing people in the private sector, and keeping them away from Government grants in various forms.

Thank you, Mr. Chairman.

Chairman RANGEL. Mr. Anthony?

Mr. ANTHONY. Thank you, Mr. Chairman.

I am concerned with what may happen in the future as soon as 1992, if not before. As revealed in your testimony we should get busy and start finding some more oil and/or find some alternate sources of energy. If not, we are going to be back in a lot of trouble.

Based on your own testimony that we are going to have to find some more oil and/or alternate sources of energy, what effect do you think the special tax breaks available to producers, both independent, and integrated will be. Do you believe these tax breaks will detract from the development of an alternate energy source or the technology of alternate sources of energy?

Mr. JANSMA. I think that we have to acknowledge that hydrocarbon energy is a dwindling resource. You can look at a normal distribution curve and see how the larger fields have been found and that we are dwindling.

However, on the other side of that, we have a very substantial amount of resources left. Just as an example, the stripper wells that I mentioned in my testimony, there are 410,000. Those wells are on top of approximately 4½ billion barrels of oil that is trapped in the rock, and that future technology will hopefully find a way to get more of that out.

So, we have a substantial amount of potential in front of us, and I think, however, even knowing that, we should not forget the alternate sources because in the long run alternates are going to be major necessities for this country.

Mr. ANTHONY. I am glad to hear you make that statement. So, your industry is not in opposition to Congress trying to help develop alternate sources of energy through special tax breaks that we have given to others. You don't find that to be in competition or life threatening.

Mr. UNSELL. We have never objected to that. We have taken the position historically that the Government should limit its participation to research and a lending role and should not be an actual participant in energy development.

So far, the Government has not participated directly. But, as you know, the great hope that we have entertained for synfuels has collapsed, and there are only two remaining projects, and one of them is very shaky.

They are back asking the Government for more money and it is a question of economics. Every time the crude oil price drops a dollar, it makes some of these energy alternatives less viable, and for this reason I think most economists that you talk to nowadays looking at the energy picture will tell you that oil and gas are going to have to be dominant elements in the energy mix through the rest of this century at least.

Fortunately, as Mr. Jansma noted, the U.S. Geological Survey indicates that we have got an oil resource base and a natural gas resource base even better, both ample, to last this country well into the next century.

Back to a question the chairman raised, this has always been a cyclical industry. From the midfifties up until 1973, we lost half of the independent producers in this industry; 10,000 of them went out.

As Sid mentioned, this industry is not closed to anyone, but no one has to be in the oil business, and when things get tight you see people leaving.

During the late fifties and all through the 1960's, we had innumerable petroleum engineers and geologists who had been entrepreneurs in the oil and gas business building motels, hotels, and bowling alleys in this country.

The one that I recall, a young geologist from Midland, Tex., built four hotels and wound up as president of the Innkeepers Association of America, and to me that sort of illustrated what happens in those down cycles in this business.

Over time, though, independent producers have done most of the drilling, found most of the oil, and they will continue to do so, given a positive economic climate.

I am convinced from having watched the situation for the last 35 years, that the tax treatment provided by the Federal Government is a vital element in that economic picture. No question about it.

Mr. ANTHONY. So, to some extent what you are saying is that if Mr. Rangel and/or others feel that there is much profit to be made in the oil business, any of them can participate and share in the riches as well as the losses.

Does that summarize what you just said?

Mr. UNSELL. This is another thing. We have the figures. We didn't insert them, but over time the Oil and Gas Journal publishes from the SEC earnings reports on about 90 independent producers. Those earnings that they publish every year for independents who are public corporations are no higher than the earnings of the 500 manufacturing companies on which the Government keeps earnings reports.

The same is true of the so-called Chase Bank group, which is the 27 largest companies in this industry. Their earnings have tracked with the earnings of businesses generally in this country and obviously if tax treatment of independent producers were inordinate or unjustified, they would be reflected in the earnings of those corporate independents. They are not.

Mr. ANTHONY. Mr. Chairman, I would request, if you could locate that article, that it be submitted as part of the record.

Mr. UNSELL. I would be glad to do that.

Mr. ANTHONY. I think that would be very beneficial.

I just have a couple of final questions.

What is your position on the oil import fee that Dr. Rivlin discussed, $2 a barrel would raise some $20.4 billion over the period, 1984 through 1988? She indicated it would help the domestic market, the alternate sources of energy, and also help our huge Federal deficit and would force us to go to conservation and slow down our reliance upon OPEC.

Sounds like a pretty good idea the way she laid it out.

Mr. **Unsell**. One of the things I have heard most since the windfall profit tax was enacted was from independent producers individually talking to me, is that it was discriminatory. If you want to limit imports of foreign oil, you put a tax on foreign oil. If you want to encourage imports of foreign oil, you tax domestic oil. That is what I call an inverted tax on domestic oil, which has had that effect.

There are a great many people in our industry that feel that that tax should have included imported oil to start with. It wasn't. We don't have a position on an import fee per se. But we do have a special committee that has been appointed to make recommendations to the IPAA meeting later this month on that very point, and we will be taking a position one way or the other.

Mr. **Anthony**. The record probably won't remain open that long, but I would hope that you would share the conclusion of that committee with us.

I think she raised a very interesting point there.

Mr. **Unsell**. There is one thing I would say further on that.

In January there were about 60 national groups, farm groups, steel companies, automobile companies, the chambers of commerce, a lot of—I would say the groups in Washington that represent the business industrial community of America were joint signers of a letter to the President urging him not to enact new energy taxes that would raise costs of energy in this country.

So I think this is one of the elements that has caused us to be a little worried because some of those people have been supportive on some of our issues, and I think you have to recognize that if you did raise—put a $5- or $10-import fee on, you would have to do that with the understanding you are going to raise everybody's energy costs significantly. At the same time that may be good.

I am not saying necessarily that it is bad. I think it is one of those things you would have to take into account.

Mr. **Anthony**. I thank you for presenting your testimony, and for hopefully, providing us with a clear record on behalf of the 15,000 independent oil producers that you represent.

Chairman **Rangel**. If the panel has any breakdown that could help us in identifying the 15,000 independents, it would be helpful. I am not talking about investors.

Mr. **Unsell**. There is a commercial reporting organization that serves our industry called Petroleum Information Corporation. It is a subsidiary of the Nielsen Co. that does the television reporting. In the last 3 years they have identified the economic entities, large, small, and in between, who have been the operators of drilling of wells in this country. They tell us that there have been over 16,000 separate and distinct business entities that have participated in drilling wells in the last 3 years. That is 1980 through 1982.

Our membership is less than 8,000. So we would only have access to about one-half of the entities involved in oil and gas exploration.

Chairman **Rangel**. I thought somewhere in your testimony you had actually broken down the size of the independents, barrels that they produce, and how many wells they have.

What do you use to reach those conclusions?

Mr. **Jansma**. I use the barrels that were attributed to the independent sector of the United States and the number of wells.

Chairman RANGEL. You broke it down to the size of the holdings of the individual independents. You said they only had 15—you said about 15 to 20 wells.

Mr. JANSMA. That is correct.

Chairman RANGEL. Where would you get that information?

Mr. JANSMA. That is information that we have available.

Mr. SCOGGINS. That information comes from the Department of Energy and several other public sources.

Chairman RANGEL. You don't have the names of these independents that you are talking about?

Mr. JANSMA. No.

Mr. SCOGGINS. We don't have—nowhere does there exist a list of the individuals who are independent producers, except at the IRS, and they have never been willing to make that information available to us.

Chairman RANGEL. Who are the members of your association?

Mr. SCOGGINS. Anyone can be a member of our association who believes in sound domestic energy policy. We are an open association.

Chairman RANGEL. You don't have to be in oil and gas to be part of your organization?

Mr. UNSELL. Yes, our people are all in the oil business or very closely related activities.

Chairman RANGEL. Are your people independent producers?

Mr. UNSELL. Yes.

Chairman RANGEL. Why can't we get a clear picture of who are the members of your organization?

Mr. SCOGGINS. Are you asking for a list of names?

Chairman RANGEL. Yes, so we can have a feel to see whether or not the average is 20, less, or whether it is 15 to 20—I don't know.

Mr. SCOGGINS. I don't think it would be legally appropriate for us to say that we would disclose those names without having checked with each and every one of our members.

Chairman RANGEL. I wouldn't want you to do anything in appropriate. I just thought maybe you could provide us with some information so we could have a better idea as to what the size would be of an average independent producer.

Mr. SCOGGINS. We can certainly provide all of that information without identifying by name the individuals involved. I don't think that would be appropriate.

Chairman RANGEL. Well, maybe you are right, but just giving us numbers doesn't help too much. But I appreciate the effort, and thank you for taking the time to testify. Certainly this particular committee and the full committee is very sensitive to your needs.

Mr. JANSMA. Thank you for your time.

Chairman RANGEL. The next panel is the Oklahoma Independent Petroleum Association. Ray M. Potts is its president. He will be testifying with the Texas Independent Producers & Royalty Owners Association: Harrold E. Wright, president, and Carolyn Linder, royalty owner, Gladewater, Tex.

Congressman Edwards, you are recognized for the purpose of introducing our witnesses.

Mr. EDWARDS. Thank you, Mr. Chairman.

I cannot really vouch for introducing the Texans here, but I am sure the gentleman from Texas will be able to do that.

I appreciate the time that you have given to those of us from Oklahoma today, and I certainly hope that the information that is being provided is going to be useful to the committee.

That is my second opportunity to be here today. I won't add any remarks of my own to what I said earlier. I was here earlier as part of the entire Oklahoma congressional delegation.

This time I have the pleasure of introducing to the committee a man who is both a friend and constituent of mine from Oklahoma City, Ray Potts. Ray is president of the Oklahoma Independent Producers Association, which has 1,300 members. He is also the chief executive officer of his own independent oil company, which is based in Oklahoma City, and therefore has the experience not just as an executive of an association, but as somebody out in the field actually producing energy.

I have had the opportunity to read his testimony and I believe you will find it very interesting. I think the entire Oklahoma congressional delegation would endorse his comments. So I thank you for allowing me to be here again, Mr. Chairmam, and introduce Mr. Potts to the committee.

Chairman RANGEL. The Chair recognizes Mr. Pickle from Texas.

Mr. PICKLE. Mr. Chairman, I am pleased to have the opportunity today to introduce Mr. Harrold Wright, president of the Texas Independent Producers & Royalty Owners Association.

Mr. Wright does an excellent job representing this organization. With him is Carolyn Linder from Gladewater, Tex.

You are welcome here.

Mr. Julian Martin is the executive director of TIPRO. He is here with Mr. Wright.

Chairman RANGEL. All right. Mr. Potts.

## STATEMENT OF RAY H. POTTS, PRESIDENT, OKLAHOMA INDEPENDENT PETROLEUM ASSOCIATION

Mr. POTTS. Thank you, Mr. Chairman and members of the committee. I am delighted to be here today.

My name is Ray Potts. I am from Oklahoma City where I am chief executive officer of PSEC, Inc. My education consists of bachelor and master's degrees in geology, and a juris doctor degree.

I am privileged today to come before you as an independent producer of domestic crude oil and natural gas, and as the representative of the Oklahoma Independent Petroleum Association. OIPA is a 1,300 member association comprised solely of independent producers and suppliers to the independent industry.

While I am representing OIPA, I will be referring often to my company for examples of how certain tax treatments affect the success of our efforts to produce oil and gas, so permit me to provide more background about PSEC.

I worked 6 years as a petroleum geologist for a major oil company before forming PSEC in 1967. Our primary purpose is to explore for and develop oil and gas reserves. We currently operate 71 wells—65 gas wells and 6 oil wells—all in Oklahoma.

In 1982, PSEC drilled 24 wells; 16 gas, 4 oil, and 4 dry; of these 24, 6 were wildcat wells.

Our drilling cost was $5.5 million, of which 27 percent was spent by PSEC and the balance—$4 million, or 73 percent—came from capital raised from outside sources.

It is my understanding that this subcommittee intends to review eight areas of the Internal Revenue Code which affect the tax treatment for different types of oil and gas producers.

As an independent and as the representative of OIPA, we would like to address three of these areas which significantly affect independents. They are:

Intangible drilling costs, percentage depletion allowance, and windfall profit tax exemption on stripper well crude oil production.

Our position on these three areas is concise and firm.

Intangible drilling costs, the percentage depletion allowance, and the windfall profit tax exemption for stripper well production are mandatory and vital to: (1) Continuing to attract the level of outside investment capital which enabled the independent petroleum industry to drill 89 percent of all wells drilled and 92 percent of the wildcat wells drilled in this country during 1982; (2) the viability and vitality of the independent petroleum industry; and (3) moving the United States toward the goal of energy independence.

It is important for this subcommittee to be aware of the definition of an independent producer and to recognize the significant contribution the independents in this Nation make toward meeting our energy needs.

I am an independent. PSEC is an independent company. We own no pipelines, no refineries, and no marketing outlets such as service stations. We simply look for and find oil and natural gas.

We are paid for our production and we pay taxes right out of our pockets with no opportunities to pass through these costs to the consuming public.

Nationwide there are approximately 15,000 independent producers. However, this number is beginning to decrease because of the severe recession that currently exists within our industry.

During the last several years, independents have found more than three-fourths of the new fields and more than one-half of the oil and gas reserves on shore in the lower 48 States.

Since enactment of the Natural Gas Pricing Act of 1978, independents have discovered and own 68 percent of all new natural gas. By contrast, majors hold 75 percent of the old gas in the country. In the lower 48 States, average daily oil production is 6.9 million, of which 2.6 million or 38 percent is produced by independents.

These discoveries have all been made possible by the ability to raise sufficient outside capital to fund drilling. This capital investment enabled independents to drill 89 percent of all wells drilled in the United States in 1981 and 1982 and an average of 91 percent of all the wildcat wells in the United States.

Independents spent approximately $32 billion to drill in 1981 and $27 billion to drill in 1982.

In Oklahoma, independents have a tremendous record. In 1981 and 1982, independents drilled 96 percent of all wells drilled in the

State and 91 and 90 percent respectively of all the wildcat wells drilled in the State.

Pursuing further the impact the independent industry has on Oklahoma, it must be noted that payments of gross production and other severance taxes to the State accounted for 27 percent of all direct tax revenue received by the State during fiscal year 1982.

Our payments of income, sales and other taxes easily make us the largest revenue producer in Oklahoma.

Gross production and other severance taxes paid to the State have grown more than 1,000 percent in the 10 years beginning in 1973, reaching a peak of $744.9 million in 1982.

That is $23.62 for every second of every day in the year and represents a payment of $240 for every man, woman, and child in the State.

In Oklahoma in 1982, 104,000 people were employed in oil and gas extraction work. During the first quarter of calendar 1983 that figure has already fallen to 82,000 because of plunging activity.

We point out that if independent producers are going to be able to continue to provide 27 percent of the tax base for Oklahoma, and reverse the trend of unemployment, we must be able to drill and that requires capital investment which is spurred by the three specific tax treatments we are addressing.

Intangible drilling cost: In my judgment, the single most important tool the independent has to raise capital to drill is the attractiveness to the investor of being able to write off the intangible drilling cost the year the expenditure occurred.

Furthermore, the investor should not be penalized by subjecting this expense to the 15-percent minimum tax—1983, alternative minimum tax increases to 20 percent.

The following is a simplified example of an investor's tax obligation with and without the 15-percent alternative minimum tax.

Investor filing joint return with two exemptions:

Total gross income, $400,000 [included in gross].

Oil and gas income, $50,000.

Oil and gas expense, $20,000.

Intangible drilling cost, $200,000.

Itemized deductions, $30,000.

Total tax with alternative minimum tax, $93,162.

Total tax without alternative minimum tax, $73,149.

Extra tax, $20,013.

I am firmly convinced that without IDC's, the independent sector of the petroleum industry could not exist as we know it today.

Percentage depletion: The original purpose of percentage depletion was to attract capital to be invested in a depletable resource; that is, a resource that has a life certain and cannot infinitely produce revenue, return on investment, for the investor. All types of natural resources currently are entitled to some type of percentage depletion.

The depletion allowance on oil and gas originally was 27.5 percent. It has been gradually reduced, contrary to the good of the industry, to 18 percent this year and will ultimately fall to 15 percent in 1984.

Following is an example of how the depletion allowance helps stimulate investment:

Oil and gas income, 1982, $100.

Less 18 percent allowance, [18].

Taxable income, $82.

The deductible income is available for reinvesting in future exploration. It should be noted that independents historically reinvest more than their average ross well revenue.

Over a 9-year period through 1980, independents reinvested nearly an average of 105 percent of their annual gross well revenue.

Next to intangible drilling costs, the percentage depletion is the second most attractive means of raising capital for an independent. However, at a time when we use 15.5 million barrels of oil per day, of which 3.3 million barrels per day are imported, I think we should be raising the percentage depletion to help attract the capital needed to find more reserves.

Windfall profit tax exemption: The third area of great importance to the independent industry is the windfall profit tax exemption for stripper well production.

That exemption went into effect January 1 of this year, but the Internal Revenue Service has proposed new stripper well definitions that could cause the loss of the exemption for several stripper wells.

Oklahoma's petroleum industry is very stripper well intensive. There are nearly 70,000 stripper wells operating in Oklahoma right now. They represent 84 percent of all the wells drilled in our State and these wells, at last report, averaged 2.85 barrels per day.

Prior to the enactment of the windfall profit tax, abandonments of stripper wells were declining. But that trend reversed, and in 1981, there were 644 abandoned wells in Oklahoma. That represents a loss of 1,763 barrels per day and that is oil that never will be recovered.

Even if the price per barrel of oil shot to $50 it would not be enough economic incentive to reenter an abandoned stripper well.

While major oil companies tend to abandon stripper wells when production drops to 5 or 6 barrels per day, independents, given the proper incentive, such as the windfall profit tax exemption, will continue to operate a stripper well so long as it is at least marginally profitable.

An example another OIPA officer presented at IRS hearings last week underscores this point. He is a partner in a stripper well that produced gross income of $3,622. He paid $256 in gross production tax to the State, had operating overhead and depreciation expense of $2,470. His net profit to that point was $1,146; but a windfall profit tax payment of $372 dropped his profit to $774.

As he said, "It won't take too much more expense or taxes to push that well into abandonment."

If it is abandoned, let's determine the areas that suffer:

Royalty owners, the company, the well servicing company, the pumper, the oil treating company, and the salt water haulers, all will lose income on which they pay State and Federal income taxes.

It will add to the tons of unsalable used equipment and salvage already on the market.

The State of Oklahoma loses the gross production tax revenue.

The Nation must replace the lost production with imported oil from insecure sources.

It has been estimated that 20 percent of Oklahoma's 70,000 stripper wells will be negatively affected—possibly forced into abandonment—if Congress permits the IRS to ignore congressional intent and, in effect, repeal the windfall profit tax exemption.

Hopefully, we have made you aware of the importance of intangible drilling costs, percentage depletion allowances, and stripper well exemption from the windfall profit tax. The recommendation we make to you—for the benefit of the independent industry and the Nation's energy supply, is to in no way reduce or eliminate these three tax treatments.

If anything, you should act just the opposite, expand the incentives and create new ones if you want to encourage the development and production of crude oil and insure the survival of the independent petroleum industry.

We offer one specific suggestion concerning an area not previously covered. Historically, there has been a flurry of investment and drilling activity during the fourth quarter of the calendar year. This is a peak time in the industry as companies try to expend remaining drilling capital and individuals make last minute investments to avoid excessive income tax.

To create more stable, evenly distributed drilling activity throughout the year, we encourage you to consider staggering the payment schedule of personal income taxes.

If, for example, people were required to pay taxes 3.5 months after the month in which they were born, you would avoid the rush of investment and drilling while at the same time lessening the burden on the tax collection agencies.

By its nature and definition, the independent petroleum industry is restricted in its avenues for selling the natural resources we produce. Production taxes, income taxes, and other tax burdens are borne by us. We cannot pass them along to consumers as integrated major companies can through the marketing of products.

Any additional taxes, be they new taxes or those created by reducing or eliminating current tax incentives, would increase the burden on the 15,000 independent producers in the United States. To be able to continue to contribute significantly to the energy needs of the United States, the independent petroleum industry must not and cannot be cut off from its lifeline—the outside investing community.

Intangible drilling cost deductions are imperative to attracting outside investment for independent exploration and development. IDC's are already being damaged by the alternative minimum tax which should be reduced, if not completely eliminated.

Additionally, the continuing decline of our percentage depletion allowance will continue to reduce the amount of funds independents have to reinvest in new exploration and production. In turn, this will create greater need for outside investing. Thus you see the damaging cycle that already faces the industry.

Further, we would recommend that the windfall profit tax exemption on stripper well crude oil production, as granted by the Economic Recovery Act of 1980, be preserved as intended by Congress.

The loss of this exemption would cripple the individual independent who survives on these small wells, while collectively increasing abandonments and negatively impacting domestic crude production.

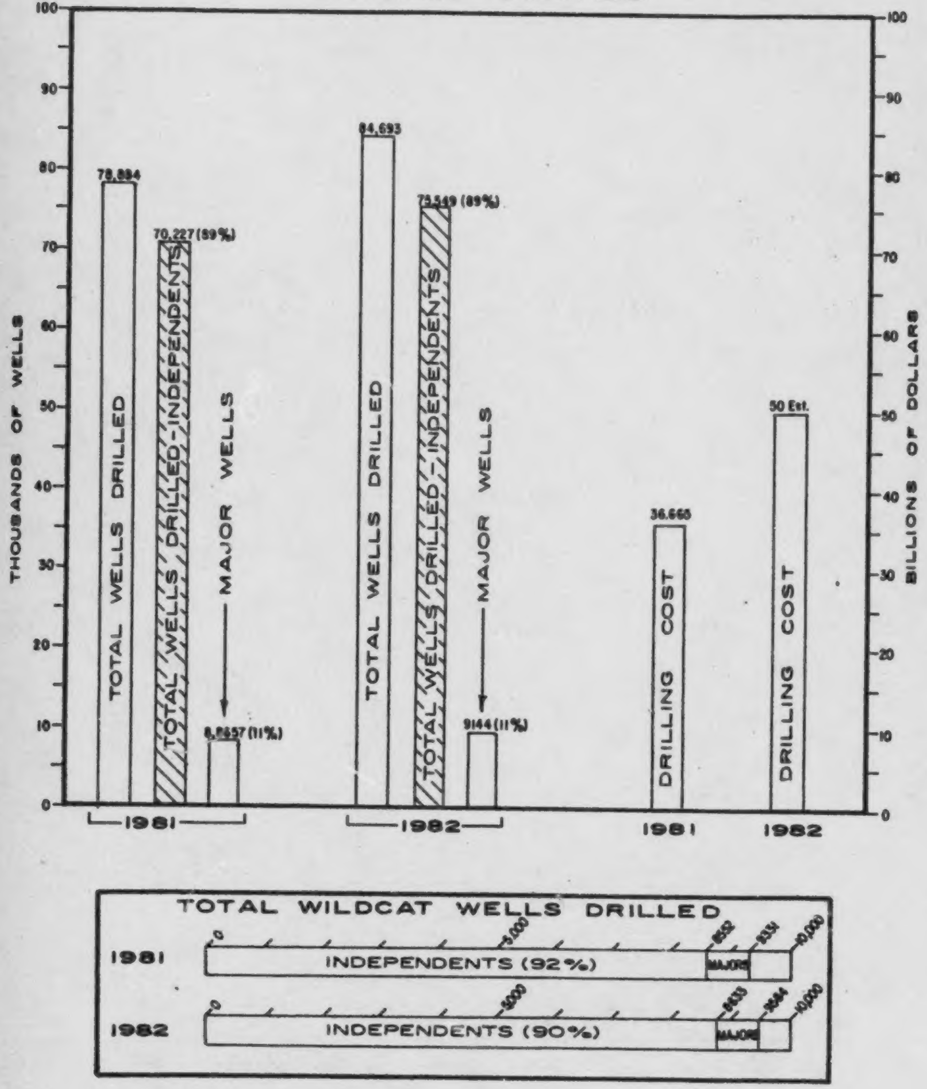
The final blow would be against the States which would have to turn to the Federal Government to compensate for lost severance tax revenue.

Finally, we encourage this subcommittee to consider revising the tax payment schedule for individual income taxes. By staggering the payment of taxes, we could eliminate the flurry of investment and drilling activity which normally occurs in the fourth quarter and, in exchange, have a consistent drilling pattern throughout the year.

In summation, the independent petroleum industry, which drills 89 percent of the wells in the United States, believes the tax incentives now granted to us are vital and must be maintained, while, at the same time, we encourage the Federal Government to explore ways to improve our lot and the Nation's energy situation even more.

[The charts referred to follow:]

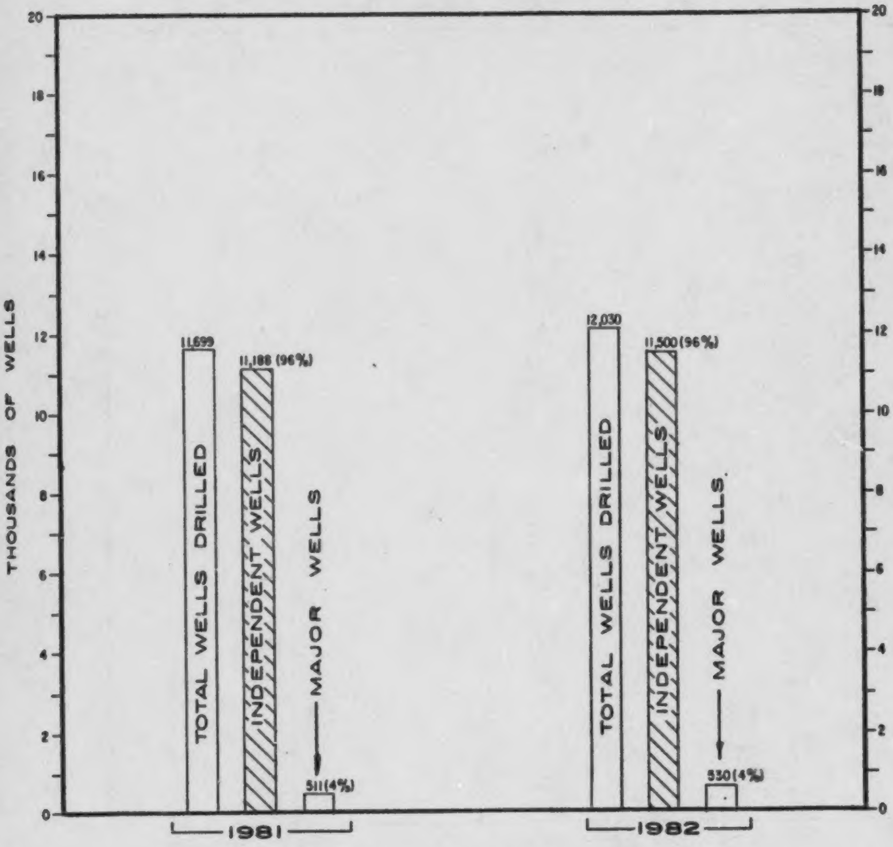
## UNITED STATES

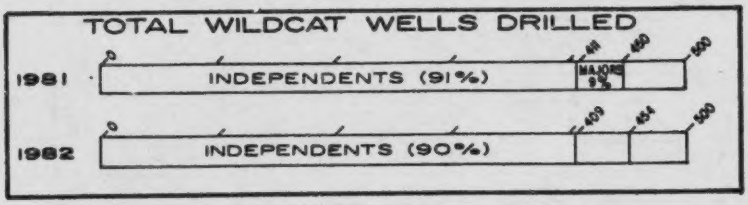


SOURCE – *Petroleum Information Corp.*
*Major – Chase Group*

CHART I

# OKLAHOMA





SOURCE - *Petroleum Information Corp.*
*Major — Chase Group*

CHART II

Chairman RANGEL. Let us hear from Mr. Harrold Wright.

## STATEMENT OF HARROLD E. WRIGHT, PRESIDENT, TEXAS INDEPENDENT PRODUCERS & ROYALTY OWNERS ASSOCIATION

Mr. WRIGHT. Thank you, Chairman Rangel. It is a pleasure to be here, members of the panel, and our thanks, especially to Congressman Pickle for his fine, generous introduction.

We are happy to tell you that we are independents, and that we have been active in the general information that was imparted here today by the IPAA and their group. And much of what we are going to be talking about will somewhat supplement what they have given you, and we are going to put it more nearly on what is happening in Texas and get it more localized as to how the tax impact is affecting us.

Well, our statement is relatively brief. I would just like to go ahead and read it if I may.

My name is Harrold E. Wright and I am an independent petroleum producer residing in Gilmer, Tex. I appear here today as president of the Texas Independent Producers & Royalty Owners Association, which has approximately 5,400 members with an oil or gas interest in Texas. My comments are directed toward the role of the independent producer in the industry, since Mrs. Carolyn Linder of our association will testify on behalf of our royalty owner membership, which provides a little new dimension to our hearing today.

### INTRODUCTION

The object of this hearing, as we understand it, is to review the differential treatment applied to independent producers under the U.S. Tax Code as opposed to other entities in the oil industry and, perhaps other industries as well. In order to understand the logic of such treatment, the role of the independent in the petroleum industry must be made clear.

An independent producer is solely in the risky business of searching for domestic oil and gas reserves and operating successful wells. He drills approximately 90 percent of the Nation's wells. He does not transport, refine, or market petroleum and petroleum products, nor does he import oil into the United States as a rule. Consequently, the independent is not in position to pass on tax burdens applied to his wellhead production since he is not involved with product sales to ultimate consumers as are integrated companies.

For these basic reasons, Congress has authorized since 1975 the preservation, in part, of vital drilling incentives for the independent in the U.S. income tax code—namely, the expensing of intangible drilling costs and percentage depletion. Further, he has been granted partial relief from the onerous crude oil excise tax passed in 1980 to encourage increased domestic drilling for oil, to expand expensive secondary and tertiary recovery programs, and to maintain production from marginal or stripper oil wells. Without the independent's input in these vital areas of domestic production, the Nation's ability to cover some two-thirds of its demand domestically would erode rapidly, opening the door to a flood of insecure costly oil imports.

In recent years, improved industry economics combined with preservation of tax incentives for independent producers has paid off for the country. Since 1979, in Texas, for example, normal production decline—stemming from reliance on old, declining giant oil reservoirs—has been steadily reduced from an annual rate of some 172,000 barrels daily to 53,000 barrels daily in 1982. This progress has been made by an independent-led increase in drilling from 16,149 wells in 1979 to 26,372 wells in 1982. Without this improvement through investment in increased drilling, the Nation would have had to import over 43 million barrels more crude in 1982 than it did at a cost of some $1.5 billion. Keep in mind these data apply only to Texas, which accounts for only one-third of domestic productions and reserves.

Unfortunately, general economic conditions now confronting the domestic petroleum producing industry assure the dramatic improvement in Texas drilling activity mentioned previously, will no longer prevail. Our Texas producers have joined the recession with a vengeance. Wellhead prices for crude oil have declined some 20 percent in recent months, while natural gas prices are now decreasing some 15 percent and gas well production has been restricted to as little as 7 percent of capacity in some areas of the State. Since virtually all oil producers produce natural gas, the decline in value and opportunity to produce gas has a direct bearing on the economic ability of independents to search for all petroleum reserves.

The value of crude oil has been kicked around here a little bit today. As we have noted, I would like to inject here that our best figure, average figure for the State of Texas from the Comptroller's Office on the most recent period, which would probably be March, I suppose, is $26.57 an average barrel. That is a gross cost. So, the quote of $30.29 is a little bit high when we have a good mix of all types of crude, as the lower figure should indicate.

Drilling rig activity in Texas has dropped some 40 percent below year ago levels, and the decline continues each week. The decline seems to be continuing. We have a recent report from last week that we are down 35 rigs. We are down to a point where it seems to be kind of sawtoothing along a little bit seeking its own level. We hope that it is going to pick up, but we are still about 50 percent off where we were on the peak.

While some of this is due to the general economic picture, much of it is due to uncertainty over what Washington may do in terms of increased energy taxes, reduction in tax incentives directly related to drilling activity, and change in natural gas pricing controls. Further erosion in drilling incentives, the subject of this hearing, can only guarantee further shortfalls in domestic petroleum supply and increased reliance on import supply in the years immediately ahead.

Current tax burdens. There are those who would suggest the domestic producing industry pays less than its fair share of taxes. The facts, however, do not support this allegation. Recent TIPRO studies reveal that in Texas, for example, a barrel of produced crude was taxed in 1982 no less than $2.96 or 9.1 percent of wellhead value, by State and local taxing jurisdictions. Add to that an average $4.78 per barrel revenue—based on current prices—generated by the Federal crude oil excise tax, and the total tax burden becomes $7.74, or more than one-fourth of gross income, before income tax assessment enters the picture.

It is true that preferential treatment of the independent under the Federal crude oil excise tax means that he pays less than the $4.78 per barrel average paid by the industry. However, data supports the contention that for every dollar per barrel taxed away from Texas independents more than 700 fewer domestic wells will be drilled. In our opinion, this more than justifies the modest relief granted independents under the excise tax, while at the same time emphasizing the unjust, self-defeating nature of the tax in its entirety.

It is a strange energy taxation policy that this Nation and its political subdivisions have, when it is recognized that each dollar of domestic oil and gas income taxed away assures less search for domestic reserves. The inevitable result in a few years will be more relatively tax free imports and less heavily taxed domestic production to meet demand. Who gains by such policy? Certainly not the taxing jurisdictions, which will lose considerable revenue by helping substitute tax generating production with untaxed imports. Next in line to be hurt will be the American consumer who must pay more taxes to fill the revenue gap, must rely on insecure foreign energy supply, and must look for the jobs that have been exported away.

Tax incentives for drilling. The Nation's 15,000 independent producers and their investors are generally small entities in the domestic producing industry. Many of them do no have the cash flow from existing production or other business operations needed to offset the high risk of searching for new reserves. Their chances of finding commercial production are little more than 10 percent in true wildcat operations. Once a discovery is made, their chances are less than half that they will further develop a discovered reservoir with additional successful wells.

Consequently, the expensing of intangible drilling costs is considered by the average independent to be a cornerstone without which motivation to drill will disappear. Again, they are not large enough, as a rule, to absorb the economic blow of adverse drilling in unsuccessful years of operation without the opportunity to write off nonsalvageable expense. In our opinion, the elimination of IDC expensing would soon leave the petroleum finding industry to large, integrated companies which can absorb the blows of inconsistent success in exploratory and development drilling. I think we would find it impossible to sell a drilling deal if we did not directly have IDC's.

As for percentage depletion allowances, independents and royalty owners view this deduction as recognition of asset depletion. Discovered reserves are the only asset they own in their business. When it is depleted through production, the assets of the business are depleted.

Recognition of reserve depletion in the U.S. income tax code is widely applied to natural resources other than petroleum. No less than 42 ores and minerals are accorded higher depletion allowances, and numerous others have allowances comparable to that applied to independent producer and royalty owner reserves.

The depletion allowance for primary oil and gas production is scheduled to fall to a permanent rate of 15 percent next year. It is our understanding that when legislation was passed in the 1970's setting this rate, it was the clear intent of Congress to permanently preserve the rate of 22 percent for oil produced through expensive secondary and tertiary recovery operations. The logic of providing this additional incentive to encourage increased recovery of known reserves is obvious. Should the law be unclear, however, on this point, we urge this committee to recommend proper clarification.

Summary. In TIPRO's opinion, it is in the best interest of the Nation and its consumers to continue to encourage domestic independent producers to perform their vital role of drilling domestic wells. Without their input, far less wells will be drilled, thereby increasing national reliance on undue increase in foreign oil. This will result in more costly and less secure supply to meet the Nation's future energy needs.

The recognition of this role in current tax law is well founded and should be retained. Further, the modest recognition currently accorded royalty owners in he form of limited exemption from the crude oil excise tax and the retention of depletion allowances should be preserved to encourage their appropriate participation in the orderly development of vital petroleum assets owned by them. Experience elsewhere in the world as well as within our own country supports the contention that private ownership properly encouraged for such development assists in the timely development of petroleum resources.

We thank you for this opportunity to be heard. We would like to introduce Ms. Linder at this time.

Chairman RANGEL. Thank you.

We look forward to listening to Ms. Linder.

## STATEMENT OF CAROLYN LINDER, ROYALTY OWNER, INDEPENDENT PRODUCERS AND ROYALTY OWNERS ASSOCIATION, GLADEWATER, TEX.

Ms. LINDER. Thank you, Mr. Chairman and members of the panel. I appreciate the opportunity to speak before you.

My name is Carolyn Linder and I live in Gladewater, Tex. I am a royalty owner whose adult life has been devoted to a struggle to preserve for my son the heritage that was left me by my forebears.

I mention struggle because I want to dispel any notion that a royalty owner simply sits at the country club shuffling cards and waiting for the royalty checks to roll in. Mine is a working operation. I am a businesswoman—as a matter of fact, I am the current president of the Gladewater Chamber of Commerce—and my hours are long. I have operated my interests under great difficulties in recent years, and I appreciate this opportunity to share with you some of the things that are depleting my resources.

At this point, I want to make it very clear that in appearing before you I am not speaking for Carolyn Linder alone but for all royalty owners, many of whom have fared worse than I. Although my testimony will deal primarily with my own situation, I want to give you some general information concerning royalty owners as a group. In Texas, oil royalty owners average about $6,250 annually. According to Senator Metzenbaum, speaking for the Congressional Record of December 14, 1981, page S15205, 73 percent of royalty owners are over 61 years of age, 45 percent are on social security, 27 percent are widows, 12 percent are disabled, and nearly 5 percent are in residential health care facilities.

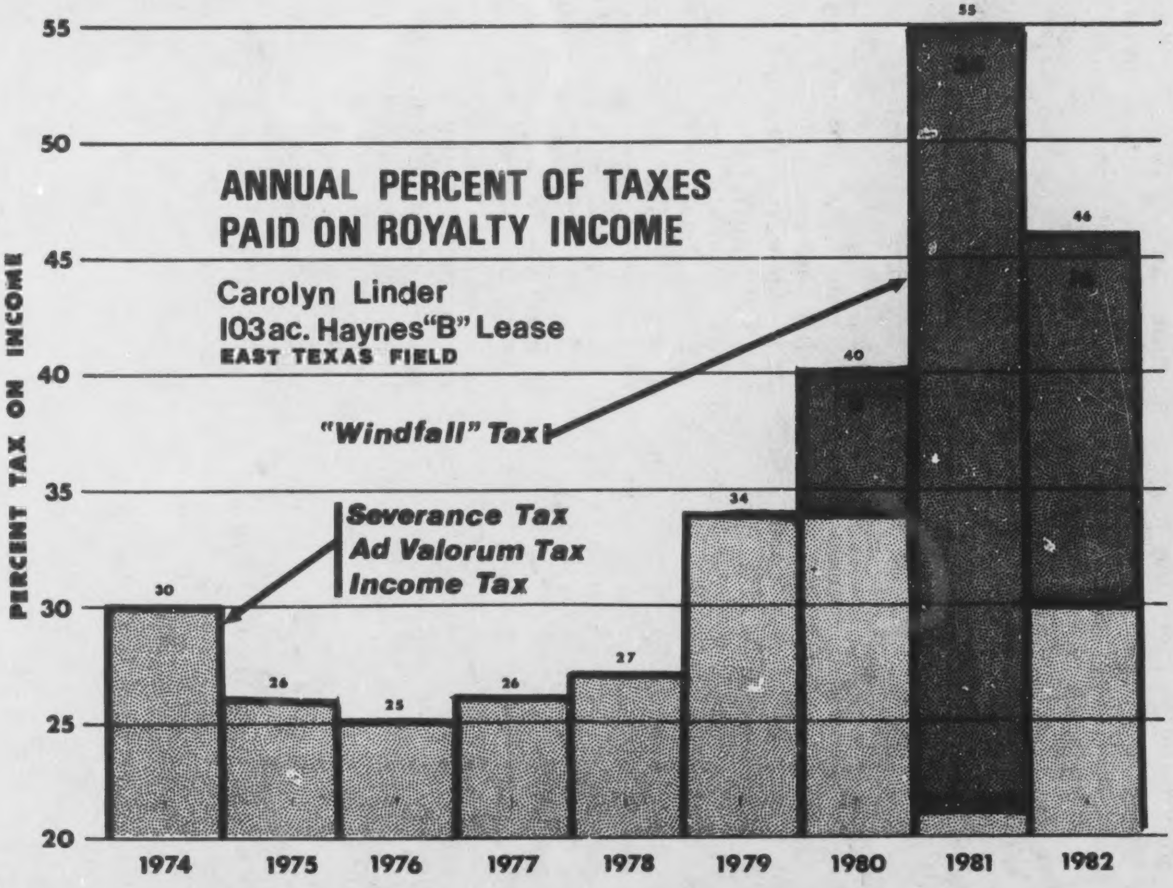
I am more fortunate than many of these people, but I have my own story to tell. In 1929, my great grandfather was truck farming the area which we will be discussing today. That year, he entered into a lease agreement with a major oil company which was successful in developing some operations. Fifty-four years later, I am bound to the terms of the lease as was my grandfather, my mother, and as my son will be after me. We have been very fortunate that the truck farm which my great grandfather founded is in the fairway portion of the east Texas field, which, as you know, turned out to be the finest oil field ever discovered in the United States.

I grew up on the Haynes lease, and I have vivid and early memories of hardships. In the sixties, with a 7-day allowable in force, I went to the bank with my mother to borrow money to pay the property tax, and I saw her cry, knowing it would take the better part of her oil checks for the next 6 months to pay it back. In 1974–80, when foreign oil was going out of sight, our old oil sold at the depressed level of $3.25 per barrel. I can assure you that we did not feel that we were the beneficiaries of a windfall.

Our old oil today is subject to very high windfall profit taxes, and I consider this an inequity. The land investment here and adjacent to us would sell for more than 20 times its original price in a like period of time. If oil had been allowed the same free enterprise opportunity, I would be getting over $60 a barrel for oil delivered from my properties.

At this time, I would like to refer you to the chart attached to these remarks. The figures were prepared for this presentation by my accountant, Mr. Odell Boles, of Longview, Tex., and I would be less than frank with you if I did not tell you that the result was shocking, even though I knew the story was not going to be a pretty one.

[The chart referred to follows:]


ANNUAL PERCENT OF TAXES PAID ON ROYALTY INCOME
Carolyn Linder
103ac. Haynes"B" Lease
EAST TEXAS FIELD
"Windfall" Tax
Severance Tax
Ad Valorum Tax
Income Tax
PERCENT TAX ON INCOME
55
50
45
40
35
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1982

Ms. **Linder**. My total tax burden on income has been as high as 55 percent. What happened to me is grim, but as I stated earlier, I have fared better than many. My husband's income plus the increased value of early land investments enables us to maintain a nice standard of living. My heart has been torn by the stories of many royalty owners who have seen their self-sufficiency blown away by the windfall profit tax.

And what really happened in my own story is that under the current tax structure, my husband's salary and returns on land investments made by my mother and I, have enabled me to keep my oil property intact. The land investments have appreciated far more than the oil. This is not just my opinion; my accountant assures me that without these add ons, I, as many friends have had to do, would have to divest myself of some of what I consider to be my son's heritage.

I am not here to solicit your sympathy. I am here to ask for a fair consideration. I have sympathy for the consumer; after all, I am one. I have sympathy for the old, the sick, and the weak; after all, I nursed an invalid mother and a blind grandfather. I have concern for the economics of living; after all, I have a son to educate.

I am asking for commonsense reasoning. I owe much to the oil and gas industry, and I am crushed to see it in its depressed state. I believe that it is overburdened with tax, including the royalty owner. I consider the two barrels a day allowance too little. I do not believe we can or should be expected to carry the load of additional taxation.

My family, like many others, survived because of a will to survive. They hung in there when the field was overdeveloped and there was no market, when oil sold for 10 cents a barrel, during the Depression when there was a surplus of oil and it was cheap, through World War II price controls, then through the glut of oil that reduced the limit allowable to 7 days a month at 20 barrels a day. We hung in there during the OPEC zenith, when domestic producers had to make way for imported oil, and we stayed on 7 days allowable with little income. Now we suffer the indignity of saying our oil is old oil, and worth less money under price controls. And then, when we have an opportunity to sell for more money, the Government calls it a windfall and severely taxes us.

In summary, my basic point is this. I, as a more favored royalty owner, am already heavily taxed by Washington. The modest exemptions in the windfall tax do not allow me to escape a heavy, highly selective tax burden. However, the vast majority of royalty owners are not well off and rely heavily on the minimal exemptions from the tax to meet living expenses.

Therefore, while I strongly believe the entire excise tax is unjust, I am particularly concerned that the limited favorable treatment of royalty owners be preserved to help ease the burden on the vast majority of small royalty owners who cannot afford to pay the tax.

Thank you.

Chairman **Rangel**. Thank you, Ms. Linder.

Are there any questions from the members?

Mr. **Pickle**. Mr. Chairman, I have two or three. I appreciate the testimony of all the panelists.

Mr. Wright, in your statement you mentioned that independent producers as a group reinvest all the money they earn.

Mr. Wright. Yes, sir.

Mr. Pickle. The earnings are plowed back into investment. One gentleman earlier testified he reinvested 108 percent at the wellhead. Why do independent producers do that?

Mr. Wright. Well, I guess we have to ask ourselves that same question sometimes, but I think there are two or three reasons why we do. One of the obvious reasons is that when these folks put together these projects they think have real value, they want to drill them and they are going to step out and they are going to be enough of an entrepreneur to put the money up and get the job done. I think that is part of it.

There is another thing. If you have your income built up to a little bit of a level, you have got to keep drilling to stay in business. We are depleting our barrels of oil every day, as we know, getting our reserves. So we have to continue drilling to stay in business. That is a second thing.

And the obvious impact of the income where you are successfully producing means you have got to, you need to reinvest those dollars. So, the industry as a whole has done a very good job, and maybe too good a job in some respects, of reinvesting their income.

Now these figures I think it has been testified earlier today are not just our figures; I believe they all come from the census department. I have seen them on several occasions. I think if my memory is correct the 1979 figure was about 116 percent; 1978 was about 105. But in the overall it has been well above 100 percent, and I believe the 108 percent was the most recent available from the census department.

Mr. Pickle. You do that in spite of the taxes imposed on you?

Mr. Wright. Well, you do it in spite of them and in conjunction with them. I think it works in concert because obviously if you did not continue to drill, and have the opportunities to expense these wells, you would be paying at the maximum tax bracket.

Also, this is the very same reason that your investors are willing to invest with you. If they like the project that you have, and they believe that it is basically a good investment, knowing that if they drill a dry hole the money can be written off, and if it is successful, then they have the opportunity of making some degree of tax deferral.

Mr. Pickle. You said in your statement that for every dollar per barrel money taxed away from the independents——

Mr. Wright. Yes, sir.

Mr. Pickle. That there would be 700 fewer wells drilled. I presume that is just for Texas.

Mr. Wright. This is a Texas figure, and we, of course——

Mr. Pickle. Please explain that for the committee.

Mr. Wright. We are talking about the typical well costing, $300,000 to $350,000. We say that is an average well. When we reduce income a dollar a barrel, equivalent dollar a barrel, then dividing that 350,000 out per well into the dollars that we end up with, by dropping $1 per barrel you are going to come up with somewhere in the neighborhood of 700 wells. That is the way we approached it. That is a Texas figure.

Mr. **Pickle**. If you multiply that by other gas and oil producing States, that means we get a lot more?

Mr. **Wright**. Over 2,000 wells for us.

Mr. **Pickle**. That could be a big help.

Mr. **Wright**. It makes a lot of difference.

Mr. **Pickle**. Mr. Wright, let me ask you and Ms. Linder, Mr. Potts——

Mr. **Thomas**. Just to underscore that, if it means 700 wells that aren't drilled, what roughly is the dry hole average? What percentage of wells drilled are dry?

Mr. **Wright**. Well, I think it has been testified here today that approximately 80 percent of the wildcat wells that are drilled are dry. Now, it is not going to be that high when you consider all wells, because wells that are development-type wells, you are not——

Mr. **Thomas**. I think the point we have to make is that we have to drill a lot of wells to find a smaller number of producing wells. And so when we talk about these large number of wells, it isn't that we aren't going to drill 700 producing wells, we should love to do that, we have to drill so many wells despite all of our scientific knowledge to average out a decent number.

So when we talk about these numbers, what we do want to impress upon you again is that the sheer economics of it is such that at $350,000 a well, we are not saying that someone is going to hit oil when they spend that 350,000; 80 percent of them are dusters.

Mr. **Wright**. This is correct, and there is no guarantee. There is no guarantee when you go into a project that you are going to get your money back even. In many instances where we think we have a well and we say 80 percent are dry holes, we also say that only 10 percent are successful. So we have another 10 percent in there that are truly noncommercial wells that we spend a lot of money on.

Mr. **Thomas**. I thank the gentleman for yielding.

Mr. **Martin**. May I put that in further perspective, Mr. Pickle? The numbers that Mr. Wright cites are equivalents to approximately 3 percent nationwide of total well drilling at current rates. So regardless of the rate of success of any given portion of that, for every dollar less accruing to independents, you would experience a drop in overall drilling of some 3 percent, which bears on some of the comments, Mr. Chairman, made earlier as to what effect these advantages or preferential treatments independents are receiving under the windfall profits tax, what might result in the way of activity.

Chairman **Rangel**. What do you base that on?

Mr. **Martin**. As Mr. Wright said, we are talking in terms of the average cost of onshore drilling, which independents concentrate on. Current costs of drilling in the field and multiplying the portion of total production carried on by independents, which approaches one-third in Texas, and dividing the sum of barrels produced by independents, multiplying that by a dollar, then dividing by the cost of wells drilled.

Mr. **Pickle**. Independents do get different tax treatment than the integrated companies. If we did not have that, do you think independent operators could stay in business? Would there be a reason for you to be there? How long would you last?

Mr. Wright. I think there is no question that the numbers of independents would decline substantially if we did not have some reasons for being in business. Some of the reasons for being in business are the tax incentives that we have, no question about it, they have to be that way. If we didn't have intangibles also that were available to us in the drilling side of it, we obviously couldn't solicit outside capital to help us drill our wells.

The point has been made several times here today. If you had to forgo that, you would only be drilling then with hard dollars of your own money probably. The percentage depletion allowance is terribly important. Obviously if you didn't have the percentage depletion allowance, you could not be reinvesting 100-plus percent of your revenues in drilling. It makes sense. It has got to add up that way. If you don't have those two things, then the industry known today will definitely dry up. And I think it has been testified earlier that we did go through a period when we had lesser prices and the economics were not with the industry, that it did dry up and you are seeing today very obviously problems that we are having in selling our gas, which has cut back our revenues, and our prices are off, our oil going down and the burden of windfall profit tax has got 50 percent of our rigs shut down. These things I think are proof positive in themselves. They are fairly obvious, I believe.

Mr. PICKLE. Ms. Linder, do you think that the royalty owner exemption should be changed; that is, two barrels be removed, or should it be maintained and go to 3 barrels as present law provides?

Ms. LINDER. I think it should be maintained. I don't think it should be removed. I would like to see it higher. I think that with your depleting resource like it is, depleting, I certainly wouldn't want to see it removed.

Mr. PICKLE. Mr. Chairman, after I have heard this testimony, half our rigs down, thousands of people out of work, with bankruptcies going on in the oil industry like they are, oil prices down in the neighborhood of $24–$25 a barrel, we might think about recommending that we raise depletion immediately.

Chairman RANGEL. It certainly should be referred to the social services committee to see what hope we can bring.

It is touching, there is no question. I had no idea what the impact was. The stories we have heard today are compelling. Of course you have told us these things many times before. Certainly the testimony here today supports your belief over the years.

Mr. PICKLE. Thank you.

Chairman RANGEL. I think we have some more stories coming from California. I want to thank you, seriously, for taking time out to testify and helping the committee to prepare a report to the full committee. And certainly if there is any additional testimony that you didn't give today that you would like to give, the record will remain open for you to do just that.

Thank you very much.

Mr. Wright. Thank you very much, Mr. Chairman.

Chairman **Rangel**. Mr. Thomas, if you have an opening statement to make as you greet the California Independent Producers, you go right ahead.

Mr. **Thomas**. I would just like to introduce from the California Independent Producers Association, commonly known as CIPA, Mr. Charles Malmgreen. He is acting executive vice president. And although in my county we are heavily involved in producing oil at the Elk Hills Naval Petroleum Reserve, we also have a number of large integrated corporations, Chevron, Shell, Getty, Union, we also have a very large number of independents, some of them operating oil wells that were discovered just about around the turn of the century.

We have heard individuals talk about how deep some of them have drilled. In my county you can find oil at ground level, or you can find it at 30,000 feet.

It is my pleasure to have Mr. Malmgreen talk about those individuals who are independent producers.

Chairman **Rangel**. May I ask Mr. Stanley Sprinkle, Jr., the chairman of the Tax Committee for the Independent Petroleum Association of Mountain States, to join us here.

Would you proceed, Mr. Malmgreen? Welcome to the committee, both of you.

## STATEMENT OF CHARLES E. MALMGREEN, ACTING EXECUTIVE VICE PRESIDENT, CALIFORNIA INDEPENDENT PRODUCERS ASSOCIATION

Mr. **Malmgreen**. Thank you, Mr. Chairman, members of the committee. I am Charles E. Malmgreen, as Congressman Thomas stated, the acting executive vice president of the California Independent Producers Association. We are located in Garden Grove, Calif.

I was going to ask for the option also to address questions that were in your May 1983 Joint Tax Committee workup. From your statement I gather that it will be possible for us to do so at a later date.

I would like to talk a little about CIPA briefly. We are a 500-plus member association, representing independent crude oil/natural gas producers, royalty holders, supply and service companies that are all doing business in California. One thing the independents in California can claim is that they produce about half the daily crude oil and natural gas output. They also drill better than 80 percent of the wells.

In my prepared comments that I passed out earlier there is a profile of, I call it overview, actually the California crude oil and natural gas industry as independents look at it. Just looking at a couple of things from the profile, I would like to mention that in California there are an estimated—this is my estimate—642 independent producers. Now approximately 600 of these producers have less than 181 barrels per day of production, but the company average statewide is 533 barrels per day.

We also have a lot of gas producers in the State, 122 of them by my best count, who produce from 69 percent of the wells. The gas wells are not very large. They produce 396 thousand cubic feet a day on average. California is the fourth largest State in oil production. It is an $11.5 billion-a-year industry. The industry produces something over 1 million barrels a day. That number has been going up steadily in the last few years.

Over the years California has produced 19 billion barrels of oil. The State estimates there are more than 5 billion additional recoverable barrels. A report by Lewin & Associates a number of years ago indicated there was as many as 20 billion recoverable barrels at a price of $20 per barrel. Now, a lot of this oil is being recovered through steam generation or chemical washes or water floods in existing reservoirs. At that rate, we are looking at something like 50 years' worth of supply in California at the current rates of usage.

The Lewin report extrapolated that a little further and indicated there could be an additional 60 billion barrels produced from California, most of that heavy oil, with techniques to be discovered in the future.

The future of California is heavy oil. Less than 59 percent of the oil—I am sorry—59 percent of the oil produced has an average gravity of less than 20 degrees API. That percentage has been climbing in the last few years.

California, as a gas producer, varies between sixth and eighth largest in the country by State. There is currently an estimated 4.6 trillion cubic feet of reserves, which is approximately a 12-year supply at current rates of use.

However, California is in a position where even with its large gas production it still imports approximately 75–80 percent of its needs.

I think a couple of remarkable things about the California industry is that it has tremendous physical assets in things such as wells, refineries and buildings, vehicles, pipelines, ships, and things like that—$32 billion worth at original cost estimates.

The industry in 1981 in terms of services purchased $4.4 billion worth. The oil industry is one of the largest employers in California. For instance, some numbers I have supplied to you indicate there are 345,000 employees in the industry, in various phases, but 38,000 of these folks are in the oil and gas extraction industry. The thing about it is that these employees are paid approximately $2 billion a year in wages, which is reinvested in the California economy.

Let's take a short note on the type of operation we have in California, because they are very indicative of the future of the industry. For one thing, in California, 57 percent of its wells are of stripper category, 10 barrels a day or less. They account for 12 percent of the production, or 130,000 barrels a day. The stripper wells produce $1.28 billion in revenue.

California ranks third, for instance, if you compare it with other States with stripper production. One thing I would like to point out about stripper production in California is that most of the wells are owned by independents, because large integrated companies find it difficult to operate these marginal wells profitably. Independents operating with less overhead can keep these wells in service cheaper. However, these wells still remain high in cost to run while providing a small profit. Loss of tax incentives such as the stripper exemption in the windfall profit tax would have a great adverse impact on independents.

As I mentioned, heavy oil is a large amount of production in California. It amounts to 641,000 barrels a day. In 1981, for example, most of it was done by steam stimulation. In some of the different areas most of that type of oil is produced in the San Joaquin Valley around Bakersfield. Another method of producing more and more oil in California is the waterflood in which they wash water through the reservoir. Most of that is done in the Los Angeles area. And something else that is coming into play is the use of chemicals, generally washed through reservoirs with water. Again, that is mostly in the Los Angeles area.

In my comments I have talked a little bit about how financing is done in California. I think I will pass on discussing that because, while it is indicated, it won't particularly mean that much to our future discussion.

One thing I should point out is, taxes are a problem in California. I testified recently on tax issues before the State legislature. California independents face a high tax load. Not only is their tax load on the Federal level similar to everybody else but California has a 9.6-percent income tax levied, which is one of the highest rates in the country. There is also an ad valorem tax administered by the counties. And depending on whose estimate you use, if you were to compare it to a severance tax, it would amount to something between 3.2 percent to 5 percent to 8 percent. The discussion of that is included in my material. Also, we have such things as barrel taxes, which cities and counties levy. Recently one of the cities went up to the new high, now 16 cents per barrel.

In looking at some things I particularly wish to point out are not just distinctive to California from the comments I have been hearing, but are things I think we would like to say. CIPA definitely endorses the need for the tax incentive we have heard discussion of and encourage the members of the committee to fully support the efforts of adjusting the IRS Code to benefit you may say the petroleum industry and our Nation. I guess benefit is really sort of a poor word.

Something I would like to dwell on a little bit, it was discussed by Congressman Thomas and it has been mentioned a couple of other places, but it is a particular problem in California. It doesn't have to do with taxes so much but it does have to do with the reason tax incentives are valuable to us. As a question of price and supply, as many of you on the panel are aware of, the independent, this is in California, does not refine his oil nor market petroleum products. Consequently, he has no control over the price paid for his oil. Prices are posted in California by four large integrated companies and are followed by most buyers. Since the independent is without a product to provide a margin, he must make his profit through the difference of wellhead revenue and the cost of production.

Such tax incentives, if you will, expensing of IDC, percentage depletion, reduced rates, and compensation in the windfall tax, help independents create a profit margin and stay competitive, or even in business, against the larger companies.

One thing to keep in mind is that California crude has characteristics similar to crude produced in other parts of the country. It sells for $5 to $6 less per barrel. The average gravity of crude in California has dropped to, now it is about 18 degrees API. What is produced in the Wilmington area sells for $22 a barrel. One of the interesting things about the California price situation is that into the mid-1970's the California crude oil prices were as high or higher for comparable oil than many other parts of the country.

There are a number of reasons why the prices have suffered a decline and created a differential that we have for today's national average price. It goes back to the Federal issuance of price controls, the later imposition of entitlement programs, and more lately the favorable windfall tax treatment of the large quantities of Alaskan North Slope crude oil.

Also, something else that entered into the picture in recent times is the Federal law prohibiting any export of domestic crude oil to a foreign country such as Japan, forcing high volumes of crude on the California market.

An interesting point; given the ramifications of short-sighted government policies, California's annual production has increased the last 4 years. Almost all California producers, large or small, are selling all the crude they produce at the present time.

However, the average California price has not risen toward the national average while production costs are approaching wellhead price—thus continued tax incentives are necessary to the California independent if he is to stay in business. That is his margin.

We support the comments of the others discussing full expensing of IDC's. This allowance is very critical in the State where the independents drill over 80 percent of the wells.

Talking about the gas well area, the independents drill 75 to 80 percent of the nonassociated gas wells. It varies from year to year. They are very successful.

In 1982, they completed 81 percent of the holes in an area where 30-percent completion rate is considered good.

However, I would like to point out the risk elements of dry holes is huge, no matter where you drill.

One exploration company drilled eight straight dusters, while a second drilled 13 straight dry holes. The average cost of a dry hole in California is approximately $450,000. Someplace down the line, you have to have some type of incentive to be able to recover those costs if you are going to be able to stay in business.

Talking about IDC's, it is the consensus of opinion among our members, and this material presented is through discussion with our members, that if IDC expensing were eliminated, most drilling in California would cease. Since the independent has less cash reserves to work with compared to large oil companies, expensing is critical to stretching the drilling dollar.

Percentage depletion is something that has been discussed a number of times today. It is a helpful tool to the independents in California. Particularly, percentage depletion has worked on the secondary and tertiary level. Since many California oil reservoirs are heavily depleted, or contain quantities of heavy oil, the higher rate for secondary and tertiary percentage of depletion has proved valuable.

To give you an idea how this works sometimes, the economics of a project can be very unrealistic. It is not unheard of for a producer to spend $18 to $20 in order to lift a $22 barrel of oil. I heard an example of a company in Long Beach who thought they were doing very well. They had monthly gross revenue of $22,000. They sat down and figured out what it cost them to run the well for that period of time, and it was $26,000. Needless to say, they are going back and sharpening their pencil.

Something that has been rather important in California is a piece of the Windfall Profit Tax Act called the alternative base price rule. It is an example of Government's policy in previous years leading to a large inequity for a certain segment of the California producers.

We have seen the case, another case of inequity in that the Congress created the exemption for Alaskan crude oil from the tax produced in certain areas north of the Arctic Circle. The Supreme Court now is considering the validity of this.

When the Joint Tax Committee was deliberating the windfall tax and created the base price, they tied it to a December 1979 uncontrolled oil price. The problem with that was that in California price increases were slower and later coming than in other parts of the country. Even the price increase in the uncontrolled market in the Midwest would be a little slower arriving in California for a number of reasons.

This comes into creating a bigger problem in that if you were to use this December uncontrolled price to create a base price and that base price is a part of your price of your barrel that is not taxed under the Windfall Act, the California producer starts with a smaller base price, because the prices were depressed in California at the time.

If California prices reach a parity on the national level—it does not have to quite be the same as the national average price—the California base price will not increase at the same rate as the base price increases for producers in other parts of the country. You end up in a period of time when [illegible] reached and a larger amount of the price is subject to the windfall tax for California producers than in other parts of the country.

We have worked on this problem [illegible]ively. It started out as a problem for California producers, [illegible]ld pay something over $3 billion in additional windfall [illegible]pared to other parts of the country.

The Congress created a mandated approach with an alternate base price. Later on, the Treasury Department went ahead and changed it more—by changing the base price rules, the inequity has been reduced to where it is only about a billion to a $1½ billions over the projected 10-year life of the tax.

We have proposed raising the multiplier factors to the base price. However, the Treasury Department has not acted.

In summary, I would like to pose a question to this panel. If being an oil producer is one's conception of owning a gold mine, then why are independents finding it tough to raise exploration and development capital? Many people would subscribe this financial drought is a result of the world oil glut. However, I think we should consider the financial hardships might be more due to this country's tax policies and the threat of loss of what tax and investment incentives still exist.

America is not petroleum-energy-independent. The Nation is currently importing approximately 4 million barrels of oil and 1½ million barrels of products daily. Instead of further reducing or eliminating the current incentives, this Congress should enact more financial incentives to encourage new investment in an industry that is critical to our economy and national security.

Thank you for this opportunity to comment.

[The prepared statement follows:]

### STATEMENT OF CHARLES E. MALMGREEN, ACTING EXECUTIVE VICE PRESIDENT, CALIFORNIA INDEPENDENT PRODUCERS ASSOCIATION

The California Independent Producers Association (CIPA) represents 500+ members who are independent crude oil and natural gas producers, royalty holders, supply and service companies doing business in California. Independents produce approximately one-half of California's daily crude oil and natural gas output, and drill over 80% of all wells. California is the fourth largest oil producing state at approximately 1,070,000 barrels per day, or more than twice as large as number five, Oklahoma.

Since other witnesses have or will be addressing the specific workings of tax preferences, allowances, special rates and exemptions for independent oil and gas producers within the Internal Revenue Code (IRC), I plan to address my remarks to only a couple of issues important to California's independent producers. However, CIPA definitely endorses the need for these tax incentives, and encourages the members of this committee to fully support efforts to adjust the IRC to benefit the petroleum industry and our nation.

In my remarks today I would like to dwell on the generalities of price and supply in the California oil market; the value of expensing intangible drilling and development costs (IDC's) to California exploration and development; benefits of larger secondary and tertiary percentage depletion allowances to incremental production; and the necessity of the alternate base price rule in the Crude Oil Excise Windfall Profit Tax Act of 1980 (WPTA).

Submitted as part of these comments is an overview of California's crude oil and natural gas producing industry from the independents' perspective. Acknowledgements cite various publications from which information was drawn; however, CIPA will gladly provide original source material upon request for areas of interest to the Committee.

#### PRICE AND SUPPLY

There are a few exceptions, but basically the California independent does not refine his oil, nor market a petroleum product. The independent also has no control over the price paid for his oil. Prices are posted by four large integrated companies and followed by most buyers. Since the independent is without a product to provide a margin, he must make his profit through the difference in wellhead revenue and cost of production. Such tax incentives as full expensing of IDC's, percentage depletion, reduced rates and exemptions in the WPTA help the independent create a profit margin and stay competitive with large companies.

One thing to keep in mind is that California crude with characteristics similar to crude produced in other parts of the country is bought for $5 to $6 less per barrel. An average 17° API gravity Wilmington crude is currently posted at about $22 per barrel. Since California crude sold at prices equal to, or higher than the national price until the early 1970's, there must be reasons for the current differential from the national average price: federal issuance of price controls which rolled back higher California prices to a national average; the imposition of the entitlements program to equalize the higher cost of imported crude with domestic oil; and more recently, favorable windfall tax treatment of large quantities of Alaskan North Slope (ANS) crude that encourages North Slope producers to land oil in West Coast refineries rather than support the crude to Gulf and Atlantic Coast refineries. The federal law prohibiting export of any domestic crude to a foreign country, such as ANS oil to Japan, is also forcing high volumes of crude into the West Coast market.

Even given the ramifications of short-sighted government policies. California's annual oil production has increased the last four years. Almost all California producers, large or small, are selling all the crude they produce. However, the average California price has not risen towards the national average, while production costs are approaching wellhead price. Thus contiuned tax incentives are necessary to the California independent if he is to stay in business.

### INTANGIBLE DRILLING COSTS

CIPA totally supports the comments of others on allowing full expensing of intangible drilling and development costs (IDC's). This allowance is critical in California, a state where independents drill over 80 percent of the wells. Independents use IDC's to drill and develop the smaller oil and gas prospects that the large companies will not touch.

Most oil wells in California are drilled to develop known reserves. Because the state has extensive "heavy oil" reserves which are the future of the industry, many of these wells are to facilitate enhanced recovery techniques such as steamfloods and chemical waterfloods. Occasionally, a dry hole is the result of $250,000 or more worth of effort.

Independents have typically drilled 75-90 percent of the non-associated gas wells in Northern California. In 1982 independents completed 81 percent of the holes in an area where a 30 percent completion rate is considered good. However, the risk element of dry holes can be huge. One exploration company drilled eight straight "dusters," while a second drilled 13 straight dry holes. The average cost of a gas dry hole is approximately $450,000.

It is the consensus of opionion among CIPA's members that if IDC expensing were eliminated, most drilling in California would cease. Since the independent has less cash reserves to work with when compared to large oil companies, full immediate expensing is critical to stretching the drilling dollar.

### PERCENTAGE DEPLETION

Percentage depletion has been a helpful tax tool to independents for years. With the existence of a carry-forward provision, percentage depletion has created cash flow for companies during periods of low oil prices and high production costs.

Since many California oil reservoirs are heavily depleted, or contain quantities of heavy oil, the higher rate for secondary and tertiary percentage depletion has proved valuable in encouraging continued use of enhancement techniques such as waterfloods, steam stimulation and chemical injection. Independents run many steam injection projects in the San Joaquin Valley, and several large waterfloods and chemical floods in the Los Angeles Basin. Often the economics of these projects is such that the cost of producing a barrel of oil is only slightly less than the wellhead price. It is not unheard of for a producer to spend $18-$20 in order to "lift" a $22 barrel of oil.

### ALTERNATE BASE PRICE RULE

Many oil producers consider the Windfall Profit Tax Act of 1980 (WPTA) an unfair inequity in an industry already highly taxes. Unfortunately, the WPTA itself imposed inequities among different producing areas of the nation. One well known case is the exemption from the tax for some Alaskan oil produced north of the Arctic Circle. The U.S. Supreme Court is currently considering the validity of this exemption.

Another example of inequity among taxpayers concerns the method by which producers calculate the base price that is deducted from the sales price of a taxable barrel of oil. The amount of price remaining after the base price and state severance tax deductions is subject to tax rates between 30-70 percent depending on production classification of the oil. The base price is adjusted quarterly for inflation.

During WPTA deliberations by the Joint Committee on Taxation in early 1980, CIPA pointed out that California producers could pay more than $3 billion in additional windfall tax when the base prices was calculated using December 1979 uncontrolled oil prices. A price differential as high as $12 per barrel between mid-Continent and California existed that December.

The inequity occurs as California's prices rise to a national average. Since California producers calculated a beginning base price $2 or $3 less than most non-California producers, this base price adjusted for inflation would not rise as high as the national average. If prices reached a par, but California producers were penalized with the lower base price, then a greater percentage of the California price would be subject to windfall taxation.

The Joint Committee agreed to develop an alternate base price calculation, and give producers the option of using the higher one. Congress also instructed the Treasury Department to make an adjustment to eliminate the inequity. In September 1980 the Treasury Department promulgated a base price adjustment.

The rule as now calculated allows a producer to multiply his field's May 1979 Upper Tier ceiling price by a factor of 1.1 for taxable Tier 2 oil, and by a factor of 1.2 for Tier 3 oil. While the alternate rule eliminates over $1 billion of the inequity, another $1-$1.5 billion still exists.

CIPA has proposed raising the multiplier factors to 1.24 and 1.35, but the Treasury Department has not acted.

## SUMMARY

In summary, I would pose a question to this panel: If being an oil producer is one's conception of owning a gold mine, why then are the independents finding it tough to raise exploration and development capital? Many people would subscribe this financial drought as a result of the world oil glut; however, I think we should consider that the financial hardships might be more due to this country's tax policies and the threat of loss of what tax and investment incentives still exist. America is not petroleum energy independent; the nation is currently importing approximately 4 million barrels of oil and 1.5 million barrels of petroleum products daily. Instead of further reducing or eliminating the current incentives valuable in discovering and producing more oil and natural gas, this Congress should enact more financial incentives to encourage new investment in an industry that is critical to our economy and national security.

Thank you for the opportunity to comment.

**CIPA**
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May 4, 1983

# AN OVERVIEW OF THE CALIFORNIA'S CRUDE OIL AND NATURAL GAS INDUSTRY; THE PERSPECTIVE OF THE INDEPENDENT PRODUCER.

By

Charles E. Malmgreen
Acting Executive Vice President

## A. California's Independent Oil and Natural Gas Operators.

Historically, California's independent has been a major producer of the state's oil. As early as 1941, independents produced 48.0% of the oil. Percentage of production over the next 40 years fluctuated to 50.2 in 1950, to 38.5 in 1966, to 51.3 in 1977, and to 49.8 in 1981. In the years from 1944 to 1981, daily state production averaged between 850,000 and the 1981 high at 1,054,172 barrels per day. (The 1982 daily average exceeded 1981.)

According to various sources, there have been approximately 650 oil companies operating annually in California in the last few years. In production reported for December, 1982 the top 36 companies (including majors) produced over 1,000 barrels per day (b/d). This is excluding the U. S. Navy Elk Hills production. If two other non-reporting companies are eliminated, the bottom eleven of the top 50 list companies produced between 1,000 and 181 b/d. Thus approximately 642 independent producers, or 98.8% of the state's total companies, were responsible for 354,885 b/d. This is 36.7% of the production after Elk Hills is removed. An independent producer company averaged about 553 b/d (Exhibit 1).

Turning to the *67th Annual Report of the State Oil & Gas Supervisor*, Division of Oil and Gas, 1981, the net gas production measured 379.5 billion cubic feet (Bcf) (1.04 Bcf per day). Associated gas from oil wells accounted for 184.8 Bcf (506.3 MMcf/d), while non-associated (dry) gas accounted for 194.7 Bcf (533.4 MMcf/d). California in recent years has ranked sixth to eighth in the nation as a gas producing state.

Since almost all the production of associated gas is taken at will, the dry gas industry can be studied through the December, 1982 CCCOP source for a typical high-volume month. One hundred thirty producers using 1,192 wells produced 576.6 MMcf/d of gas. If the seven majors and U. S. Navy Elk Hills production is eliminated, then 122 companies sold 324.1 MMcf/d of gas from 819 wells. This means the small producer sold approximately 396 Mcf/d per well. (Exhibit 1).

### B. Independent Producer Source of Exploration and Development Funds.

California's independent oil and natural gas producer finds his funds for exploration and development from a variety of sources. Unfortunately, while the economics for drilling are good, downside prices for oil and unsure sales for natural gas are currently depressing activity. Lease costs, rig costs and some equipment costs are all down from 1980-81.

### Oil Financing

Currently one of the more popular sources of financing for oil exploration and development is *industry partnerships* or at times *joint ventures*. Some *limited partnerships* with outside investors (including offshore interests) are in common use by a few companies. A few limited partnerships have been constructed on a payout of *advanced royalties* to the outside partners, whereby the royalty interest can be as high as 43% while the remaining 57% belongs to the working interest. Some companies use stock offerings to raise capital while others construct matching grant programs with insurance companies. Banks through the offer of a line of credit have become less of a source of funds. However, more and more of the medium independents are turning to internally generated funds to provide capital for expansion.

### Gas Financing

Although there are more than twice the plays available than being drilled in any one year, the lack of investor funds has choked development of California's dry gas prospects. During the 1980-81 active years, producers were able to put together limited partnerships with money from out-of-state, particularly Denver. However, these funds have become very shy in 1983. Another source of funds in the recent past came from the state's large gas-buying public utilities. Unfortunately, the utilities have taken to leasing land for their own exploration efforts. More and more the gas producers have turned to independent oil companies for exploration and development funds.

Recent changes in the federal tax code have also made investments in other types of financial instruments more attractive. When the marginal tax rate was 70%, the allowed write-offs and preferences for investing in oil and gas plays provided reasonable incentives for investment. Now that the industry rate of return has dropped to 11-12%, other financial opportunities with higher rates of return abound. As one of our members recently said, "If everyone thinks oil and gas wells are such a good thing, then why aren't more people investing?"

### C. California's Resource Base.

California has been a prolific producer of crude oil over the last century. At one time in the early 1900's, the state led the nation in [illegible] production. Of the ten largest producing fields in 1981, seven were discovered over 50 years ago. The oldest of the 10, and second largest producing field in 1981, Midway-Sunset, was discovered in [illegible]. [illegible] of the fifty-year plus fields showed production increases in [illegible]. Total cumulative production to January 1, 1982 from all oilfields is [illegible] billion barrels (1981 CCCOP). The 1981 DOG Report estimates recoverable oil reserves, as of December 31, 1981, at 5.1 billion barrels. This estimate does not include reserves from OCS activity off the coast.

Much of the future of California's oil production industry lies in the ability of producers to recover "heavy" oil, and also oil still remaining in older, depleted reservoirs. (The federal government definition of "heavy oil" is oil with a gravity of 20.0° API or less.)

In 1976 the Federal Energy Administration released a study by [illegible] & Associates that concluded a potential 20 billion barrels of oil could be recovered from already discovered California oilfields if the price of oil were to rise to approximately $20 per barrel. The oil would be recovered by means of steamfloods of existing fields, or by [illegible] "waterfloods" through older, heavily depleted oilfields. [illegible] year supply at current production rates. The [illegible] concluded that another 80 billion possible barrels of oil [illegible] if recovery techniques were sufficiently improved. [illegible] of the heavy oil reserves in the United States are [illegible] California.

Production of California's heavy oil has steadily increased [illegible] forty years until by January, 1982 641,470 b/d, or 59.2% [illegible] production was of less than 20° API gravity. Almost [illegible] active wells were engaged in heavy crude production (1981 CCCOP).

## Gas

Again turning to the 1981 DOG report, recoverable gas reserves, as of December 31, 1981 were estimated at 4.6 trillion cubic feet, or approximately a 12-year supply at current useage rates.

## D. Expenditures in Local California Economy.

The petroleum industry plays an important part in California's economy. In 1981 petroleum products accounted for 82.2% of the value of all minerals with crude oil first, and natural gas third. Total value of the petroleum production is estimated at $11.5 billion (1981 IPAA).

According to statistics prepared by the Western Oil and Gas Association, the original cost of the physical assets of the oil industry in California, as of January 1, 1982 amounted to more than $32.2 billion. The property represented in this investment included: oil and gas wells, refineries, crude oil and refined product pipelines, office buildings, terminals, tank trucks, tank cars, tankships, and thousands of retail and wholesale marketing outlets. In 1981 the state oil industry pruchased services and materials totaling $4.4 billion. Services and materials expenditures represented approximately $40,000 per direct industry employee.

## E. Service and Supply Industries.

California has an extensive service and supply industry dependent on exploration and production of the states petroleum reserves. There are about 20 drilling contractors running approximately 113 rigs. Most of these rigs are employed in the state. There are about 16 oil-well servicing contractors with approximately 324 servicing rigs all of which operate within the state (POW). Almost all the large pipe, down-hole and surface equipment manufacturers are represented through a vast network of supply companies. Most of the California banks, and many banks from other areas of the country do business in the oil and gas patch. Also there are the ancillary companies such as vacuum truck operators, oil transport tankers, mud companies, logging companies, geophysical and engineering companies.

## F. Employment

Using the 1981 WOGA survey, it can be estimated that almost one million persons obtain their livelihood from the California petroleum industry. This would include 345,600 employees on the payrolls of oil companies, retail service station dealers and bulk plant dealers. Employees of supply companies and oilfield contractors serving the industry are not included. The IPAA 1982 annual survey estimates almost 38,000 people are directly employed in oil and natural gas extraction within the state.

Direct employees of the industry in California earned over $2.1 billion in 1981, or about $24,137 per person. These wages were of course recycled into the economy in the form of payments, taxes and savings (WOGA).

## G. Type of Operations of Local Operators.

The type of operations conducted by California's independent oil and natural gas producer are very diverse. Over 96.6% of the wells are on pumps or artificial lift because of the low viscosity of the oil, or lack of pressure in reservoirs. In most production areas of the state, secondary or tertiary enhancement methods are required to produce the oil.

### Greater Los Angeles Basin

This area totaled 81.1 million in 1981, or approximately 222,191 b/d. The basin is the second largest producing area in the state. About 47.3 million barrels was the result of incremental production from enhanced recovery projects: 40 million from waterflooding, 3.4 million from basically steamfloods, and 213,000 barrels by chemical waterfloods. This area contains many small and medium sized independent producers (DOG).

## South-Central Coastal Region

The region produced 21.2 million barrels in 1981, or approximately 58,082 b/d. The area is heavily faulted due to numerous ancient and active landslides among extensive mountains which has resulted in few large oil pools and many small pools. The dominant method of production is by waterflood 88%, with little gas injection and some steam injection. Since drilling is more expensive than in other area; only a few independents have production (DOG).

## Central Coast

The Central Coast area produced 26.8 million barrels in 1981, or approximately 73,424 b/d. Reservoir stimulation resulted in 17.2 million barrels: waterfloods, steamfloods, cyclic steam and 127,000 barrels due to fireflood. There are a number of independents operating in the area (DOG).

## San Joaquin Valley

This area is the largest oil producing district in the state [illegible] million barrels in 1981, or approximately 615,342 b/d. Most [illegible] area is flat with some gentle hills. One of the fields was dis- [illegible] in 1894 and is still the second largest producer in the state. [illegible] 104.2 million barrels, 46%, was produced by reservoir stimulation. [illegible] injection accounted for 101.4 million barrels, and waterflooding [illegible] fireflooding another 2.8 million. A large number of the independents [illegible] in this area on generally medium to small operations (DOG).

## Central California Region

This region produced 11.6 million barrels in 1981, or approximately 31,780 b/d. The area is generally flat with many small producers. About 58%, or 6.7 million barrels were produced by steam injection projects (DOG).

## Northern California

This area is mostly known for dry gas production, however, 209,000 barrels of oil were produced. Non-associated gas production in 1981 amounted to 183.8 billion cubic feet. The huge Rio Vista gas field west of Sacramento was responsible for 21% of the production. There is a tremendous number of small and medium sized companies doing business in the district. They rely primarily on natural reservoir pressure for the production method (DOG).

## Stripper Production

All of the above oil production areas have some stripper production with the Los Angeles Basin and San Joaquin Valley totaling the largest numbers. Stripper wells are an important part of California's oil industry. The 1981 CCCOP tabulates that 27,059 (57.7%) of the 46,938 oilwells state wide produced less than 10 barrels per day. If wells producing between 10 and 15 barrels per day are considered, the 31,567 or 67.3% of the wells produce less than 15 barrels per day. The state daily average is about 20 barrels per well. Compounding the stripper numbers is the fact that approximately 55% of the total statewide production is heavy oil.

According to IPAA statistics, stripper oil accounted for 130,780 b/d, or 12.4% of the state's 1,054,679 b/d. The approximate wellhead value of this oil was $1.275 billion. California generally, ranks around third in stripper production, and fifth in number of wells when compared with other producing states. Stripper wells and production are the heart of California's independent producer.

It should be pointed out that most stripper wells are owned by independents because the large integrated oil companies find it difficult to operate these marginal wells profitably. The independents operating with less overhead can keep these wells in service cheaper. However, these wells still remain high in cost to run while providing small profit. Loss of tax incentives such as the stripper exemption from the Windfall Profit Tax would have a great adverse impact on independents.

## H. State and Local Tax Burden.

Taxes on California producers, when compared to other states, rank among the highest in the country. These taxes include a state income tax, county ad valorem tax on mineral rights, a state production tax, and local barrel tax.

A study conducted by R. L. Neal and M. E. Reed of David P. Cook & Associates, Dallas, Texas, and published by World Oil magazine, August 1, 1982 placed California at the top of the list of states with extremely high oil taxes of the top 15 states with oil and natural gas production. While some large oil producing states have no income tax at all, the study found that California had the largest corporate income tax rate at 9.6 percent of net income.

Further, the Neal-Reed study compared oil and gas production taxes. While California may not assess a major severance tax on production as do other states, few other states have the equivalent of our ad valorem tax which was estimated to be about 8% for purposes of the study. The State Board of Equalization has projected the ad valorem to be equivalent to a 3.2% severance tax on wellhead price. However, the validity of this 1980 number is doubtful since the assessors of the larger oil production counties have taken to bending the state law, Proposition 13, which placed a cap on assessment increases for all real property. Mineral rights are real property in California. A correct severance value might be closer to 5-6%.

There are two other small taxes to consider. The state levies a miniscule production tax, less than 1/100 of a percent, to run the State Division of Oil and Gas. Secondly, many counties and cities also assess a barrel tax, ranging from 3 to 16¢ per barrel. The average is about 10¢.

Summing up, the Neal-Reed study concluded that the total state and countytax burden assessed on production and mineral rights in California placed the state among the other two highest taxing entities, North Dakota and Alaska.

Summary of December, 1982 California Oil and Dry Gas Production*

| Major Companies | Company Production B/D | | Dry Gas | |
|---|---|---|---|---|
| | | | Daily Mcf | Wells Producing |
| Shell | 170,907 | | 15,479 | 46 |
| Chevron | 141,412 | | 77,258 | 103 |
| Getty | 134,636 | | 3,402 | 23 |
| Mobil | 54,042 | | 11,471 | 72 |
| Union | 49,834 | | 74,786 | 35 |
| Texaco | 36,405 | | 40,774 | 60 |
| ARCO | 24,577 | | 13,107 | 13 |
| | 611,863 | 56.0% | 236,277 | 352 |
| U.S. Naval Reserve (Elk Hills) | 126,762 | 11.5% | 16,230 | 21 |
| | 738,625 | | 252,507 | 373 |
| 642 Independents (Estimated) | 354,885 (1) | 32.5% | --- | --- |
| 122 Independents | | | 324,100 (2) | 819 (3) |
| State Totals | 1,093,510 | 100.0% | 576,600 | 1,192 |

*Numbers Courtesy of December, 1982 Company Record of California Oil & Gas Production, Conservation Committee of California Oil Producers (CCCOP).

(1) Average per independent - 553 b/d.

(2) " " " - 2,657 Mcf Daily.

(3) " " " well - 396 Mcf.

**EXHIBIT ONE**

## ACKNOWLEDGEMENTS

1. 1981 Annual Review of California Oil and Gas Production, Conservation Committee of California Oil Producers, Los Angeles. (1981 CCCOP)
2. Company Record of California Oil & Gas Production, December 1982, Conservation Committee of California Oil Producers, Los Angeles. (Dec'82 CCCOP)
3. 67th Annual Report of the State Oil & Gas Supervisor, 1981, California Department of Conservation, Division of Oil & Gas, PR06, Sacramento. (DOG Report)
4. Projected Recovery and Economics of Heavy Oil, Lewin & Associates, Washington, D. C., 1976 Report for Federal Energy Administration. (1976 Lewin)
5. The Oil Producing Industry in Your State, 1982, Independent Petroleum Association of America, Washington, D. C. (1982 IPAA)
6. Economic Importance of the West Coast Oil Industry-As of January 1, 1982, Western Oil and Gas Association, Tax and Statistics Department, Los Angeles, (WOGA)
7. Drilling Contractor and Well Servicing Report. Pacific Oil World, August 1982 issue, Brea, California. (POW)
8. "Onshore U. S. ...Taxes Can Cause Up To 93% Variance In Cash Flow," R. L. Neal and M. E. Reed, David P. Cook & Associates, Dallas, Texas, as published in World Oil, August 1, 1982.

Chairman RANGEL. Thank you, Mr. Malmgreen.

Mr. Sprinkle?

## STATEMENT OF STANLEY G. SPRINKLE, JR., CHAIRMAN, TAXATION COMMITTEE, INDEPENDENT PETROLEUM ASSOCIATION OF MOUNTAIN STATES, AND ENERGY PARTNER, PEAT, MARWICK, MITCHELL & CO., DENVER, COLO.

Mr. SPRINKLE. Mr. Chairman, members of the committee, I am Stanley G. Sprinkle, Jr., from Denver, Colo., the chairman of the Taxation Committee of IPAMS.

I would like to highlight my testimony.

The Independent Petroleum Association of Mountain States represents over 1,800 members in 11 Rocky Mountain States. Its only office is in Denver, Colo.

We are 9 years old and have a professional staff of approximately 5 people. Most of the work for the association is done by volunteers, such as myself.

The independent oil companies differ from the majors in a number of ways besides size, of course.

Generally, the independents have a single profit center at the wellhead. Since the independents' profitability is dependent almost exclusively on oil and gas production, they have traditionally devoted a higher percentage of revenues to exploration and development than the majors. I think this has been discussed several times today.

The numbers I have, which are a little older than the numbers reflected by the IPAA in their testimony, indicates that independents have spent on the average of 105 percent of their gross wellhead revenues on exploration and development costs as compared to 70 percent by the majors. Accordingly, the independents have drilled most of the wildcats, 89 percent, and have accounted for the majority of new fields found, 75 percent, and new oil and gas reserves discovered, 54 percent.

Their share of the lower 48 State production has increased from 29 percent in 1969 to 33 percent in 1978.

Several of these statistics are set forth on the graph facing page 2.

From 1977 to 1981, the percentage of new wells drilled by the majors declined each year vis-a-vis the independents. In 1982, the trend was reversed, however, as independents felt the economic pinch. Nevertheless, independents drilled 90 percent of all new field wildcats, and 88 percent of all oil and gas wells completed during 1982.

Thus, it is the independents to whom the Nation must largely look to take the risks involved in finding new sources of oil and gas.

There is no typical Rocky Mountain independent oil company. The vast majority, however, are small, often a sole proprietor.

There are over 1,000 petroleum firms in Colorado with three or fewer employees, with only 15 employing more than 150 persons. These small firms are generally owned by a company executive in his fifties, holding a degree in geology or petroleum engineering.

They are often referred to as wildcatters, and may have experienced a bankruptcy on occasion.

The Rocky Mountain region is making a substantial contribution to the Nation's oil and gas supply. Of the 84,693 oil and gas wells drilled nationally in 1982, a record 8,214 were completed in 11 Rocky Mountain States. Two thousand fifty-six of these wells were wildcats, which resulted in the discovery of 315 new oil fields and 115 new gas fields.

This activity came despite the high level of risk inherent in drilling in the region.

This risk can be seen in the fact that 3,124 of the wells were dry holes. That is, 38 percent of all wells drilled in the Rockies were dry. That includes wildcats and development wells.

Compare this to 697 dry holes out of 10,400 wells drilled in the Appalachian Basin, only slightly less than 7 percent were dry holes.

So, as you can see, the Rocky Mountain region is such a frontier area, and many wildcat wells are being drilled to discover new oil and gas fields.

The average well drilled in 1982 in the Rockies was 6,235 feet deep. The easy areas have been fully drilled up. Thus, the industry must look to greater depths and to remote areas with the lack of access and rough terrain, making moving in a drilling rig an expensive proposition.

Besides the inherent risk and cost of drilling in the Rockies, other negative factors impacting the industry indicate that a downturn is definitely in process in the Rocky Mountain region right now.

Companies have heavy debt burdens from expansion during the recent period of strong oil demand. New tax burdens, such as the alternative minimum tax, have made investment in oil and gas drilling less attractive.

The contributions of the oil industry to the regional economy involves much more than taxes it pays. For example, the Denver Regional Council of Governments estimated that 82,200 new jobs in the Denver area were attributable to the energy industry between 1970 and 1980. This direct and indirect employment represents one-fourth of the total of all new jobs in Denver for that time period.

Each new industry-linked job induced 2¼ additional jobs, as compared to 1.8 new jobs for other industries.

In Colorado, as a whole, the oil and gas industry is estimated to directly employ 35,000 persons with a payroll of over $700 million annually. This is estimated to induce over 70,000 additional jobs with an annual payroll of over $1 billion.

Each $1 increase in income in the Colorado oil and gas industry is estimated to result in a $2.31 increase in total Colorado revenue.

While Denver is the center of the regional energy activities, other areas have also prospered from oil and gas development. Casper, Wyo., has seen its population grow from 39,500 in 1980 to 60,000 in 1982. Since 25 percent of the jobs in Casper are directly related to oil and gas, and many of the others are indirectly related, the current downturn has had a severe impact on the whole economy.

I am told that unemployment stands at 22 percent in Casper, approximately twice the national average.

State and local taxation is another factor affecting our industry in the Rockies. The oil and gas industry is subject to numerous State and local taxes, including sales and use taxes, excise taxes, and income taxes.

In addition, the industry is subject to double taxation on the full market value of its production by virtue of the county levied ad valorem taxes and State severance taxes.

Finally, the value of oil and gas production is generally assessed at two to three times the rate of other classes of real property in the States.

In Montana, the estimated total tax burden, State, local and Federal, on $1 of crude oil revenue to a working-interest owner is 74 cents. This is illustrated on page 6 in my testimony. You can see for each $1 of revenue to the working-interest owner, 42 cents goes in the form of Federal and State and local production taxes. That includes the windfall profit tax. That only leaves approximately 58 cents to cover all other expenses, including State and Federal income taxes. If you throw those in, the producer has about 26 cents left to cover all his operating expenses, dry holes, equipment, et cetera.

States are increasingly turning to increased taxation of the oil and gas industry as a solution to their budget woes. Decreases in Federal funding have accelerated this trend.

During the 1982 legislative sessions, 25 States considered increasing the tax burden on oil and gas production, including raising severance taxes, and eliminating the deduction for the Federal windfall profit tax.

An added complication for the oil and gas industry is presented by the probability of new taxes imposed by Indian tribes in the Rockies. The Supreme Court has affirmed tribal sovereignty in this area.

The tax burden on the oil and gas industry is a significant factor in the current downturn. A recent study asserts, and I will quote,

> The notion that the "Windfall Profit" tax, severance tax and other production taxes generate revenue for their collectors is often ill-founded. Increasing the fraction of revenues taken by these taxes can readily render valueless an otherwise potentially valuable productive property. The result is that the "collectors" coffers receive nothing at all."

The oil and gas industry in the Rocky Mountain region is undergoing a substantial downturn. This can be seen in the fact that the number of drilling rigs at work has dropped from [illegible] in mid-1981 to 204 in early 1983. That is a 73-percent reduction in the rig count.

There has been a severe reduction in the capital available for oil exploration. Independent oil and gas producers raise most of this capital from individual investors. In the first quarter of 1982, public drilling funds produced 40 percent less exploration capital to the industry than in the first quarter of 1981. Investors are wary due to the slack demand, falling prices, and the new alternative minimum tax, as well as the risk of additional taxes on the industry.

Another indication of the industry downturn can be found in the number of stripper well abandonments. This number increased for the first time in recent years during 1981. The impact of the windfall profit tax is cited as a reason. And it is hoped that the January 1, 1983 exemption for independents will produce a turnaround of this abandonment.

The independent oil company is significantly different from a major oil company. Therefore, there are sound public policy reasons to preserve those tax incentives that Congress has previously established for the independent oil industry.

All of the incentives that you are hearing testimony on today and tomorrow are needed.

Independents take more risks and find more new oil and gas than the majors. As with any economic activity, higher risk requires a higher return potential in order to attract capital. Tax incentives permit the independent to take these drilling risks and find new energy sources for the Nation.

Due to the complex geology and geographic remoteness, the Rocky Mountain independent is perhaps the biggest risk taker of all the oil companies drilling onshore.

As recent discoveries have shown, the region has a significant contribution to make to the Nation's oil and gas supply.

High interest rates, slack demand and falling prices have taken their toll on the domestic oil and gas industry. Activity in the Rocky Mountain region has slowed considerably. The imposition of new tax burdens on the independents will compound this trend.

The independents do not have the diversified vertically integrated profit centers of the majors, which allow the majors to offset their tax burdens through other lines of business. Nor do they enjoy the majors' cash flows and easy access to the capital markets.

Additional taxes will likely result in further drilling declines, increased well abandonments, and excessive rate of company failures. This could produce an unhealthy concentration in the industry and a reduction in the competition.

Other negative consequences could include a reduction in oil revenue to States and local treasuries, high energy prices and increased reliance on imported energy.

The decrease in State and local revenues would coincide with the period of declining Federal funds. Higher energy prices could hinder or abort the economic recovery that is presently in process.

Increased reliance on imported energy would weaken our national security, worsen our balance of trade, and strengthen the hands of the OPEC cartel.

As increases in oil and gas taxation may result in a decrease in GNP, through a disincentive to capital formation and expenditure, further tax receipts may actually decline as wells are abandoned, companies fold, and production drops.

We urge the committee to resist the temptation to regard the domestic oil and gas industry as an endless source of additional tax revenues. In particular, we ask that you recognize the unique nature and contributions of the independent oil companies and the validity of those tax incentives necessary to insure its continuing vitality.

I wish to thank you for this opportunity to testify here.

[The prepared statement follows:]

## STATEMENT OF THE INDEPENDENT PETROLEUM ASSOCIATION OF MOUNTAIN STATES

### Introduction

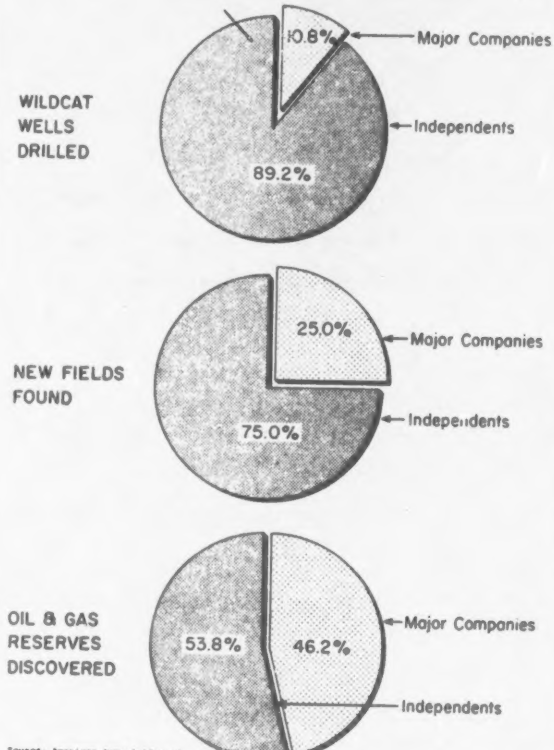
The Independent Petroleum Association of Mountain States represents over 1,800 members in the eleven Rocky Mountain states. Our members include independent oil and gas producers, professional support firms, technical support firms, royalty owners and numerous other individuals involved in producing America's energy. IPAMS is nine years old and has a collective professional staff of five people. The major strength of the Association comes from active members like myself who give of their time voluntarily to represent the independent oil and gas industry in our region.

### The Role of the Independents:

The independent oil companies differ from the majors in a number of ways besides size. Generally, the independents have a single profit center, at the wellhead. Majors, on the other hand generate profits from refining and retailing, as well as by diversification into other energy (coal, uranium, petrochemicals) and non-energy businesses. They enjoy economies of scale and employ vertical integration as a means of tax reduction. For this reason, independents are more sensitive to oil prices and demand, drilling costs, and tax burdens.

Since the independents' profitability is dependent almost exclusively on oil and gas production, they have traditionally devoted a higher percentage of revenues to exploration and development than the majors. Over the period 1973-1977 independents spent, on average, 105% of gross wellhead revenues for these purposes, compared to 70% by the majors (24 largest companies). Accordingly, independents have drilled most of the wildcat wells (89% from 1969-1973), have

## ROLE OF INDEPENDENTS



Source: American Association of
Petroleum Geologists

IPAA Chart

accounted for the majority of new fields found (75% from 1969-1973) and new oil and gas reserves discovered (53.8% from 1969-1973). Their share of lower-48 production has increased from 29% in 1969 to 33% in 1978.[1]

(See graph on facing page.)

From 1977-1981, the percentage of new wells drilled by the majors (the "Chase group") declined each year vis-a-vis the independents. In 1982, the trend was reversed, as independents felt the economic pinch. Nevertheless, independents drilled 90.1% of new field wildcats and 88.4% of all oil and gas wells completed during 1982. Thus, it is the independents to whom the nation must largely look to take the risks involved in finding new sources of oil and gas.[2]

There is no "typical" Rocky Mountain independent oil company. The vast majority, however, are small, often a sole proprietorship. There are over a thousand petroleum firms in Colorado with 3 or fewer employees, with only 15 employing more than 150 persons.[3] These small firms are generally owned by a company executive in his fifties, holding a degree in geology or petroleum engineering. They are often referred to as "wildcatters" and may have experienced a bankruptcy.

The Rocky Mountain Petroleum Province:

The Rocky Mountain region is making a substantial contribution to the nation's oil and gas supply. The ten producing states (Idaho has no current production)

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1. American Association of Petroleum Geologists, reported in Oil and Gas Journal, 1980.
2. Petroleum Information, Vol. 3, No. 1, 1983.
3. The Petroleum and Mining Industries in Colorado: a fact book, Central Bank of Denver.

provided an estimated 267.3 million bbl of oil and 1,404 Bcf of natural gas in 1981.[4] Development of the Overthrust Belt, considered the most significant find since Prudhoe Bay, is predicted to add 180,000 bbl/day by 1987, as well as 1.3 Bcf/day of natural gas.[5]

Of the 84,693 oil and gas wells drilled nationally in 1982, a record 8,214 were completed in the eleven Rocky Mountain states. 2,056 of these wells were "wildcats," which resulted in the discovery of 315 new oil fields (29% of the national total) and 115 new gas fields (15% of the national total). This activity came despite the high level of risk inherent in drilling in the region. This risk can be seen in the fact that 3,124 of the wells were dry holes (38%). Compare this to 697 dry holes out of 10,400 wells drilled in the Appalachian Basin (6.7%).

The Rocky Mountain province is a frontier area, with complex geology and costly drilling. The average well drilled in 1982 was 6,235 feet deep. The easy areas have been largely drilled up; thus, the industry must look to greater depths and to remote areas where the lack of access and rough terrain make moving in drilling rigs an expensive proposition. These areas may also be environmentally sensitive, demanding costly mitigation measures.

Besides the inherent risk and cost of drilling in the Rockies, other negative factors impacting the industry indicate that a downturn is likely in the region during 1983. Companies have heavy debt burdens from expansion during the recent

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4. Western Oil Reporter, 6/82.
5. Rocky Mountain News, 1/23/83.
6. Rocky Mountain News, 1/9/83.

period of strong oil demand. Falling prices and reduced gas "takes" have lowered company earnings. New tax burdens, such as the alternative minimum tax, have made investment in oil and gas drilling programs less attractive. A recent sampling of independents showed that many had cut their exploration budgets, by an average of 27%.[7] The nation as a whole will feel the impact of this downturn in the form of reduced domestic supplies in future years.

Impact on Regional Economy:

The contribution of the oil industry to the regional economy involves much more than the taxes it pays. For example, the Denver Regional Council of Governments estimated that 82,200 new jobs in the Denver area were attributable to the energy industry between 1970 and 1980. This direct and induced employment represents one-fourth of the total of new jobs in Denver for that time period. The study estimates that the "ripple effect" of energy-related spending is greater than in other industries. Thus, each new energy-linked job induced 2.25 additional jobs in the metro area. For other industries the induced job multiplier was estimated at 1.6.[8] Oil and gas firms occupy approximately one-quarter of the office space in downtown Denver, bringing in rental fees of $40 million annually.[9]

In Colorado as a whole, the oil and gas industry is estimated to directly employ 35,000 persons with a payroll over $700 million annually. This is estimated to induce over 70,000 additional jobs with an annual payroll over $1 billion.

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7. Rocky Mountain News, 1/9/83.
8. DRCOG study by Browne, Bortz & Coddington, 2/82; reported in Western Oil Reporter, 2/83.
9. Supra note 3.

Other direct expenditures by the industry in 1980 (exclusive of taxes) included $770 million in value added, $709 million in procurements, and $284 million in capital expenditures. Each $1 increase in income to the Colorado oil and gas industry is estimated to result in a $2.31 increase in total Colorado income.[10]

While Denver is the center of regional energy activities, other areas have also prospered from oil and gas development. Casper, Wyoming has seen its population grow from 39,500 in 1970 to 60,000 in 1982. Commercial real estate values have risen from as low as 50¢/square foot to $8/square foot and the number of banks has doubled. Since 25% of the jobs in Casper are directly related to oil and gas, and many of the others are indirectly related, the current downturn has had a severe impact on the local economy.[11]

In the Overthrust Belt itself, an estimated 9,700 persons were involved in drilling, construction and related activities along the Wyoming-Utah fairway during 1982. The population of Evanston, Wyoming doubled in 2-1/2 years. While this trend is expected to decline somewhat over the next decade, continued development of the fairway, including gas treatment facilities, should result in significant permanent employment.[12]

State and Local Taxation:

The oil and gas industry is subject to a plethora of state and local taxes, including sales/use taxes, excise taxes, personal property assessments and corporate income taxes. In addition, the industry is subject to double taxation

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10. MRI report to IPAMS, 1/82.
11. Western Oil Reporter, 5/82.
12. Western Oil Reporter, 9/82.

ROCKY MOUNTAIN STATES
1980*

| | | Production Oil and Gas | Production Taxes Assessed Oil and Gas | | Lease-Royalty Income To State | |
|---|---|---|---|---|---|---|
| Colorado | Oil | 29,801,524 bbls | Severance | $ 18,010,500.00 | State Lands | $ 10,997,559.00 |
| | Gas | 191,805,615 MCF | Ad Valorem | $ 44,483,100.00 | Federal Lands | $ 25,055,492.00 |
| Montana | Oil | 29,583,804 bbls | Severance | $ 22,906,597.00 | State Lands | $ 48,220,537.00 |
| | Gas | 53,802,088 MCF | Ad Valorem | $ 65,219,201.00 | Federal Lands | $ 11,808,646.00 |
| Nebraska | Oil | 6,239,652 bbls | Severance | $ 3,401,072.00 | State Lands | $ 1,533,196.00 |
| | Gas | 2,500,276 MCF | Ad Valorem | $ 7,525,000.00 | Federal Lands | $ (negligible) |
| North Dakota | Oil | 41,000,000 bbls | Severance | $ 118,200,000.00 | State Lands | $ 55,400.000.00 |
| | Gas | 50,000,000 MCF | Ad Valorem | $ (not levied) | Federal Lands | $ 9,700,000.00 |
| South Dakota | Oil | 910,000 bbls | Severance | $ 764,000.00 | State Lands | $ 6,000,000.00 |
| | Gas | (negligible) | Ad Valorem | $ (not levied) | Federal Lands | $ (negligible) |
| Utah | Oil | 24,977,683 bbls | Severance | $ 11,173,379.00 | State Lands | $ 17,007,761.00 |
| | Gas | 87,765,597 MCF | Ad Valorem | $ 32,873,745.00 | Federal Lands | $ 17,026,954.00 |
| Wyoming | Oil | 125,683,216 bbls | Severance | $ 67,088,040.00 | State Lands | $ 35,211,628.00 |
| | Gas | 381,825,017 MCF | Ad Valorem | $ 110,414,000.00 | Federal Lands | $ 109,736,756.00 |

*Most recent year, some numbers are calendar year 1980, while some numbers are fiscal year July 1, 1980 - June 30, 1981.

on the full market value of its production by virtue of county-level ad valorem taxation and state severance taxes. Finally, the value of oil and gas production is generally assessed at 2-3 times the rate of other classes of real property. In Montana, the estimated total tax burden (state, local, federal) on each $1.00 of crude oil value is 74¢. This is illustrated by the following which is an actual 1982 example of oil production in Glacier County, Montana.

| | |
|---|---|
| Gross Revenue to the Working Interest | $ 1.0000 |
| Less: | |
| Windfall Profit Tax (Federal) | .2265 |
| Severance Tax (State) | .0500 |
| Net Proceeds Tax (County) | .1382 |
| Resource Indemnity Tax (State) | .0050 |
| Conservation Tax (State) | .0002 |
| Personal Property Tax (County) | .0005 |
| Net Before Income Tax | .5796 |
| State Income Tax (Marginal Rate 11%) | .0637 |
| Federal Income Tax (Marginal Rate 50%) | .2580 |
| Net Proceeds to Producer | $ .2580 |

Severance taxes on oil and gas production provide 87% of all state severance tax receipts. Overall, severance taxes have risen from 2.7% (in 1970) to 4.1% (in 1977) of total state (with severance taxes) tax receipts. Between 1970 and 1977, total state tax receipts rose 111% while severance tax collections rose 216%.[13]

(See graph on facing page.)

States are increasingly turning to increased taxation of the oil and gas industry as a solution to their budget woes. Decreases in federal funding have accelerated this trend. During the 1982 legislative sessions, 25 states considered increasing the tax burden on oil and gas production, including raising severance tax rates and eliminating the deduction for the federal windfall profit tax.

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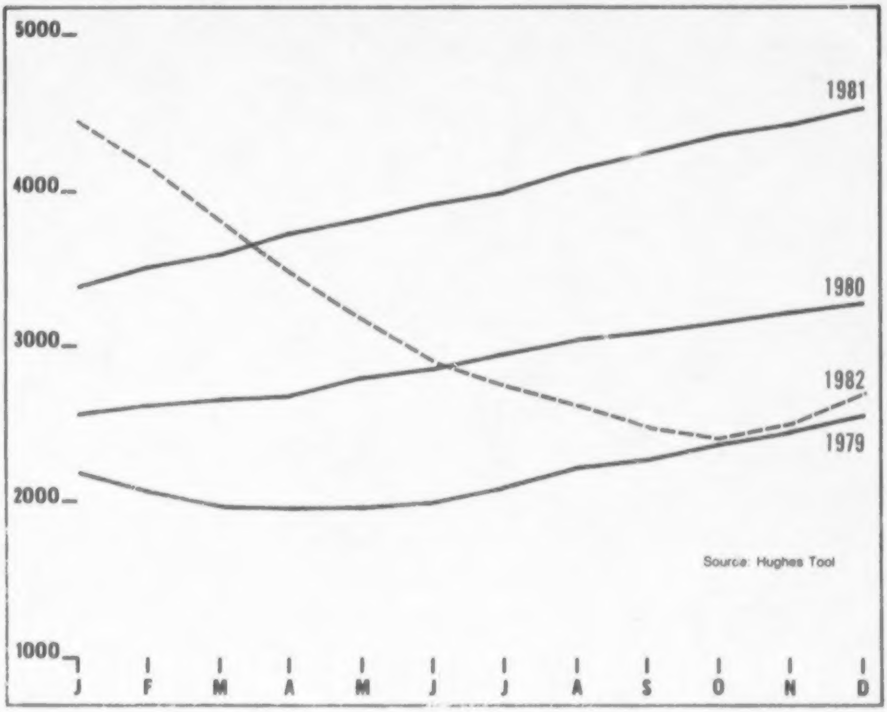
13. U.S. Bureau of Mines, study by Karl Starch.

## U.S. Rotary Rig Activity 1979-1982



Source: Hughes Tool

An added complication for the oil and gas industry is presented by the possibility of new taxes imposed by Indian tribes. The Supreme Court has affirmed tribal sovereignty in this area in Marrion vs. Jicarilla Apache.

The tax burden on the oil and gas industry is a significant factor in the current downturn. A recent study asserts: "The notion that the 'Windfall Profit' tax, severance tax, and other production taxes generate revenue for their collectors is often ill-founded. Increasing the fraction of revenues taken by these taxes can readily render valueless an otherwise potentially valuable productive property. The result is that the 'collectors' coffers receive nothing at all." The study finds that increases in production taxes decrease both the bonus payable on a barrel of oil, as well as the optimal production rate. It further finds that the economic viability of a prospect is much more sensitive to production taxes (and royalties) than to other cost and timing economic factors which affect a prospect's value.[14]

Current Financial Picture in Region:

The oil and gas industry in the Rocky Mountain region is undergoing a substantial downturn at present. This can be seen in the fact that the number of drilling rigs at work has dropped from 755 in mid-1981 to 204 in early-1983.[15] For the first time in three years the number of rigs available in the region has declined and the utilization rate has dropped precipitously.[16] These factors will likely produce both a shake-out in the oil servicing industry and a drop in the number of wells drilled. This will result in lower oil and gas production in years to come.

(See graph on facing page.)

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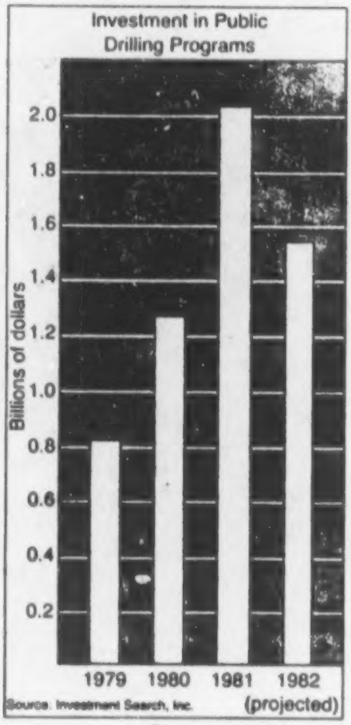
[14] Lohrenz, Dougherty & Burzlaff, "Production taxes: stealthy killer of revenue," Oil and Gas Journal, pp 68-71, 2/7/83.
[15] Rocky Mountain News, 3/10/83.
[16] Western Oil Reporter, 12/82.



Investment in Public Drilling Programs

Source: Investment Search, Inc.

The drop in rig activity has produced a cost-savings opportunity for oil companies with the cash to drill. Drill pipe costs are down 25 to 40% and "workover" rates for maintaining and repairing wells are down 20 to 50%.[17] However, this opportunity coincides with a severe reduction in the capital available for oil exploration. Independent oil and gas producers raise most of their capital from individual investors. In the first quarter of 1982, public drilling programs produced 40% less exploration capital to the industry than in the first quarter in 1981.[18] (See graph on facing page.) Investors are wary due to slack demand, falling prices and the new alternative minimum tax, as well as the risk of additional taxes on the industry. Moreover, internal cash flow of independents has dropped. A survey of 180 independents showed an aggregate 15.6% decline in earnings during the first half of 1982.[19]

(See graph on facing page.)

Another indication of the industry downturn can be found in the number of "stripper well" abandonments. This number increased for the first time in recent years during 1981. The impact of the windfall profit tax is cited as a reason, and it is hoped that the January 1, 1983 exemption will produce an upturn.[20]

## Independent Incentives/Public Policy:

As has been shown in earlier sections of this statement, the independent oil company is significantly different from a major oil company. Therefore, there are sound public policy reasons to preserve those tax incentives which Congress has previously established for the independent oil industry. These include: the ability to claim percentage depletion for up to 1,000 bbl of oil a day (or the equivalent in gas); the ability of individuals to elect to capitalize intangible drilling costs (IDCs) over 5 years (which avoids the alternative minimum tax) and claim the investment tax credit; the ability to expense 100% of IDCs; reduced windfall profit tax rates on the first 1,000 bbl/day; the windfall profit tax exemptions for stripper and royalty oil; the deposit schedule of windfall taxes permitted independents.

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[17] RMN, 4/17/83.
[18] Western Oil Reporter, 6/82.
[19] Oil and Gas Journal, 10/11/82.
[20] Supra note 16.

Independents take more risks and find more new oil and gas than the majors. As with any economic activity, higher risk requires a higher return potential in order to attract capital. Tax incentives permit the the independent to take these drilling risks and find new energy sources for the nation. Due to geologic complexity and geographic remoteness, the Rocky Mountain independent is perhaps the biggest risk taker of all the oil companies drilling on-shore. And, as recent discoveries have shown, the region has a significant contribution to make to the nation's oil and gas supply.

High interest rates, slack demand and falling oil prices have taken their toll on the domestic oil and gas industry. Activity in the Rocky Mountain region has slowed considerably. The imposition of new tax burdens on the independents will exacerbate this trend. The independents do not have the diversified/vertically-integrated profit centers of the majors, which allow the majors to offset their tax burdens through other lines of business. Nor do they enjoy the majors' cash flows and easy access to the capital markets. Additional taxes will likely result in further drilling declines, increased well abandonments and an excessive rate of company failures. This would produce an unhealthy concentration in the industry and a reduction in competition.

Other negative consequences would include a reduction in oil revenues to state and local treasures, higher energy prices and increased reliance on imported energy. The decrease in state and local revenues would coincide with a period of declining federal funds. Higher energy prices could hinder or abort the economic recovery which seems to be in progress. Increased reliance on imported energy would weaken our national security, worsen our balance of trade and strengthen the hand of the OPEC cartel. Even the environment could suffer, since petroleum shipping presents a greater hazard than on-shore drilling.

An increase in oil and gas taxation may result in a decrease in GNP through a disincentive to capital formation and expenditure. Further, tax receipts may actually decline as wells are abandoned, companies fold and production drops. IPAMS urges the Committee to resist the temptation to regard the domestic oil and gas industry as an endless source of additional tax revenues. In particular, we ask that you recognize the unique nature and contributions of the independent oil companies and the validity of those tax incentives necessary to ensure their continuing vitality.

Thank you for this opportunity.

Chairman **Rangel**. I thank both of you.

At this time, I will ask Mr. Anthony, of Arkansas, to continue to chair the subcommittee.

Mr. **Anthony** [presiding]. Mr. Campbell, do you have questions?

Mr. **Campbell**. Briefly, Mr. Sprinkle, let me go back to one of the things that you spoke of very quickly there, and I think it is very important that we pay attention to it, and that is the gross revenue in the taxation. The figure you have here is that overall there is approximately a 74-percent tax before there is any return.

Is that a correct statement?

Mr. **Sprinkle**. That is a correct statement. I believe that is on page 6 in the testimony. That is an actual example of oil production in Glacier County, Mont., of an independent operating in that county.

Mr. **Campbell**. That says something about the price of energy sometimes along the way, I guess. Maybe we in government are guilty of keeping the consumer's price a little high through our taxation. And I think it often needs to be pointed out that when you have three-fourths of the total revenue going to taxes, it does, in fact, distort the perception of the public and others as to what the oil industry really is.

And I think it is very graphic, and I just wanted to point it up once again.

Let me ask you a couple of other questions.

You made mention here that there were problems in attracting capital investment—about a 40-percent falloff, I believe, if memory serves me correctly.

Mr. **Sprinkle**. That is right.

Mr. **Campbell**. If, in fact, this committee made any changes in the law as it now exists, to take away any of the differentials that we have, would that exacerbate that problem and make capital harder to come by?

Mr. **Sprinkle**. Yes, it would, Mr. Campbell.

I would say the deduction of intangible drilling costs is very critical to the independent in his ability to raise capital. I think that was testified to earlier. When an independent is looking for sources of capital, his sources are usually individuals, as I have indicated. And to the extent that that individual is not able to deduct currently the intangible drilling costs, then that capital is not available.

I think you can probably refer back to the year 1976, when Congress first added as a tax preference item to the minimum tax the deduction of intangible drilling costs. In that particular year, intangible drilling costs became a tax preference item, and there was no net income offset. Many independents that year paid substantial minimum tax on their drilling.

Congress changed the law in 1977 and for the years thereafter by providing a net income offset against the IDC preference amount.

However, I think that illustrated the need of intangible drilling costs because it caused a reduction of capital. Not only internally did the independent have less dollars, but also he discovered that the external sources, the individual investor, was not willing to spend the dollars if he did not get a 100-percent deduction without the possibility of any tax on that deduction.

**Mr. Campbell.** The independents' access to the financial market is certainly not that of the larger integrated companies. Is that correct?

**Mr. Sprinkle.** That is very true. Most independents, as I indicated earlier, particularly in the Rockies, is probably conducting business as a sole proprietor versus a corporation. Therefore, he does not have the capital market source as he cannot sell stock and reach that market. His source is strictly individual investors or possibly the bank.

**Mr. Campbell.** The testimony all day long has indicated that the independent takes more risks; that they are the ones that are making the new discoveries.

In your opinion, does the tax difference that we have now in the Tax Code, that treats independents differently, and gives him the opportunity to take that risk, do you think we would destroy that opportunity?

**Mr. Sprinkle.** I think it most definitely gives him the opportunity to continue to take that risk. I think you will find in the early part of my testimony, reinvesting 105 percent of the gross wellhead revenue relates to years 1969 through 1973. That was the most current number that we had.

However, the Independent Petroleum Association of America testified that that number is now 108 percent which represents later years. So I think you can see, when you started providing in the incentive for the independent, which I think the first time that was done was in 1975, through retention of percentage depletion, and then the other additions that you have had, such as continued deduction of IDC, the reduction in the windfall profit tax rates, that the independent is using those incentives to reinvest.

**Mr. Campbell.** In the other figures you have given on page 2, it says that 88.4 percent of all oil and gas wells completed during 1982 were drilled by independents. Obviously, something is working to keep them active. If they are producing that much of the new wells, they are also developing that much higher percentage of the new wells. If we were to take away the incentives, is there any reason to believe that there would be others to fill the void, or would we just lose that amount of search capability?

**Mr. Sprinkle.** I think you would find that you would lose a substantial portion of that search capability. Primarily because the majors are more involved in the development of properties, once the production is discovered. Therefore, their dollars are going for development versus exploration.

**Mr. Campbell.** One other thing that I think we ought to point out, from a tax standpoint is the independents' income from the wellhead. There is not a tax shelter or another investment available to them. They don't have the integrated facility for other tax advantages. They also, in many instances, are not in a position to offset their tax burdens through other lines of business, as some of your larger integrated companies are.

Is that correct?

**Mr. Sprinkle.** That is correct.

**Mr. Campbell.** So, in fact, there are some tax advantages in the integrated companies that the independents do not have when the question arose as to why don't we treat everyone the same. If we were to put the independents on the exact same basis as we do the integrated companies, would we not in fact be giving some advantages to the integrated companies while the independents had none?

Mr. SPRINKLE. That is very true.

Mr. CAMPBELL. There would be a differential in that direction?

Mr. SPRINKLE. Yes.

Mr. CAMPBELL. Is it not a fact that the Tax Code has been developed to provide incentives for people to do certain things; to buy a house, the deduction of interest, the ownership of property, capital investment, depreciation schedules, and other items that we deem to be in the public good. We have written the Tax Code to promote that public good. Is it not a true statement on the Tax Code?

Mr. SPRINKLE. Yes, that is a true statement. And to sort of illustrate that with one of the more recent changes that has been introduced in the Tax Code, is the ACRS provision and the effect it has on real estate investment. And the independent gas and oil producers find that is one of the reasons it is harder now to raise additional investment capital dollars, because individuals are now deciding that real estate is less risky. You don't have a dry hole in real estate; you build a building and you get something back.

ASRS provides rapid depreciation deductions and, therefore, due to the rapid deduction and less risk, more of those dollars are chasing real estate now instead of investment in oil and gas.

Mr. CAMPBELL. So, if we were to take any action in this committee that would raise the level of taxes now paid by the independents above the 74 percent that they are now paying in State, local and Federal taxes, we in fact would provide a disincentive for exploration. In fact, it could have an adverse impact on the development of energy in this country, which could create higher consumer prices and a larger dependence on imported oil. Is that a correct statement?

Mr. SPRINKLE. That is most definitely the truth.

Mr. CAMPBELL. I thank you for being here today, and I think your testimony has been most enlightening, as has the testimony of the others that have been here.

Finally, I commend you on one point made in your testimony; that there is a point of diminishing returns in taxation. Sometimes if you tax somebody 100 percent, there is no incentive to go out and do anything. The return is zero. If you are at 74 percent right now then we are sure borderlining any incentive that they have.

Thank you, sir.

Mr. SPRINKLE. Thank you.

Mr. PICKLE. I appreciate the testimony. I am glad you came because we need to keep the record straight. We are not asking for relief, we are asking for facts.

Mr. ANTHONY [presiding]. Mr. Thomas?

Mr. THOMAS. Thank you very much, Mr. Chairman.

I want to compliment the gentleman from South Carolina for clearly indicating the tax implications. Just one comment on your testimony. You indicated the drill level was about 6,300 feet, so you are hitting oil at about sea level.

Mr. SPRINKLE. That is about right.

Mr. THOMAS. There was a comment made by the first witness this morning, Dr. Alice Rivlin, Director of the Congressional Budget Office. The comment was neutral tax treatment would help insure that the most efficient producers remain in business, while the less efficient ones are weeded out. I think in your testimony you indicated clearly that you have to be careful about how you define efficient producers. You made a statement—I want you to repeat it and amplify on it—about the production of stripper wells. Roughly what percentage of oil produced in California comes from strippers? Do we know that?

Mr. MALMGREEN. Yes, we do. Stripper oil is approximately 12.8 percent of California production.

Mr. THOMAS. So 10 percent of the production of oil in the fourth largest producing State in the United States is stripper wells. You indicated that in fact a number of those would not be operated if we had, in essence, what is advocated by the Congressional Budget Office, of neutral tax treatment, if we removed incentives on the stripper wells.

Would you amplify on your statement? As you recall, you indicated that larger integrated companies are not as efficient.

Mr. MALMGREEN. Over the years, if you were to, I will have to admit I can't go back as many years as some folks. If you were to look at practices in California, some of the other areas, where independents are very active and where you have major oil companies, you would find that even a well on part of a property, in cases, got to the point where it was a very low producer, the major would spin it off. Wells that are operated by larger companies have to support more people per well than, say, an independent producer is willing to work with. He works on a much slimmer overhead. In fact, the independent producer quite often goes out and services his own wells: he measures the tanks, greases the pumps, does all the necessary things in order to keep his well pumping. In a larger company, you have a pumper that goes around and does all these things. However, he has a support echelon above him that go into the office staff and many officers and things of that nature in a corporation.

Mr. THOMAS. It is your opinion that if we had neutral tax treatment we certainly would probably have less production?

Mr. MALMGREEN. If you had a neutral tax treatment, thinking back to some testimony I wrote 3 years ago on stripper wells, the number of active stripper operators in California at the time estimated any well producing less than 5 barrels a day would be uneconomical. This is before the windfall tax and its provisions were applicable.

I would assume today that margin would be the same. You would eliminate companies with practically all the wells in California, or any other State, that produced less than 5 or 6 barrels a day. In California, I haven't got the numbers right in front of me, but it seems like there is something in the neighborhood of, I think, 4,000 wells producing 5 or less barrels a day in California. But I am not real sure about that.

Mr. THOMAS. Am I correct in recalling that in your testimony you indicated that the average gravity of oil in California produced today is 18?

Mr. MALMGREEN. It has been dropping over the years. It is down to approximately 18½.

Mr. THOMAS. What is the industry definition for heavy oil?

Mr. MALMGREEN. Well, the definition is in two means. The industry for a long time, API, for instance, used—generally used an assumed definition of about 26.0. However, when the producers in Caifornia of 1970-78 began to actively work for the Department of Energy and Congress to release price controls on what they considered heavy oil, although the talking point was 26, everyone was really working with 20.0 as the break; that on down would be heavy oil.

However, the way it turned out when President Carter got involved in decontrolling heavy oil, if you remember, August 1979, he first decontrolled oil from 16 gravity and then later decontrolled the heavy oil at 20 gravity and on down. That was December 1979.

Mr. THOMAS. So generally——

Mr. MALMGREEN. We look at heavy oil being anything from 20.0 gravity down.

Mr. THOMAS. So, the average oil produced in California, by definition, is heavy oil?

Mr. MALMGREEN. Yes, it is.

Mr. THOMAS. Thank you very much. No further questions.

Mr. ANTHONY. I wish you would clarify something for me. From what I have read and what I have heard people say, I assume that most of the activity in the Mountain States was done by the large integrated majors because of the development of an overthrust belt formation. I noticed on page 3 you state how many wells were completed in the 11 Rocky Mountain States. There is no breakdown in your statement as to how many of those were done by independents. There is no breakdown on the total investment that has been made by integrated companies versus independents. I wonder if you have any of this information.

Mr. SPRINKLE. I am sure we have got some of that available and we can provide that to you to introduce into the record later if you want. I don't have it with me. There is no question in the overthrust most of that is done, most of the exploration there is done by majors and larger independents. However, that is a small portion of the 8,000 wells that were drilled.

Mr. ANTHONY. A small, or large portion?

Mr. SPRINKLE. That is a small portion. The overthrust drilling is a small portion of the total 8,000 wells drilled.

Mr. ANTHONY. Would you anticipate that the evidence would show that more of the wells are being produced by the independents or by the majors in the Rocky Mountain area?

Mr. SPRINKLE. I think without question the record would really show that definitely more than 50 percent of all those 8,000 wells were drilled by independents versus majors.

Mr. ANTHONY. If you could send some additional data on that, I think it would be interesting. Many members probably share the same perception of the Rocky Mountain area as I do; that it consists mainly of very large independents, or the majors.

Mr. SPRINKLE. I think one other part of the testimony that would help support a majority of the wells are drilled by independents is supported by the size of the companies disclosed on page 2. There we indicate that there are over 1,000 petroleum firms in Colorado with 3 or fewer employees, with only 15 employing more than 150.

Mr. Anthony. I saw that. Again, it didn't break it down to those actually out there doing the drilling. I know there are a lot of related businesses that are supported by this industry, and I was trying to justify how important economically the tax incentives are as a whole to those 11 States versus what they may represent to the State of Texas, Arkansas, Louisiana, Oklahoma, or some of the other States.

We have heard from Texas and from Oklahoma, and are going to hear from Arkansas in a few moments. The record has made it clear that independents are predominant. I would like to have a comparison of some type of regional breakout. If you have any of that data available you can submit it for the record.

Mr. Sprinkle. Yes; I will try to get some of this data for you and submit it to you.

One thing I didn't point out, on the chart that is facing page 6 deals with severance taxes only. They have been collected by seven of the States in the Rockies on oil and gas, and I think you can see the substantial amount of revenues raised locally and how the States look to this industry to provide revenues for their budgets. The total State tax receipts rose 111 percent while the severance tax collections rose 216 percent. So, I think you can see how important the industry is to the local States in their budgets.

Mr. Anthony. I have a feeling the Governor of the State of Arkansas is going to have read those same numbers and eventually will be looking at the same thing.

Mr. Malmgreen. I might add you are talking about independents being a—in California we have a mountain ridge in the area around, northwest of Los Angeles, into the Ventura area, and the independents are very active there versus the major oil companies, also.

However, the independents are a little more substantial than your stripper operators in that they are considered close to a, say, medium-size independent, where they have a couple thousand barrels a day of production. However, one of the problems I think you find in the Rockies, and it is true in the California coastal areas, is the land is, the geology is so faulted that you don't find very many large reservoirs, either oil or gas.

In California, we are talking about oil in particular; consequently, the major companies are not as interested many times in exploring this region and even investing the money in drilling up leases whereas the independents will. That is their nature.

Mr. Anthony. Sounds good. Thanks to the committee for your participation and your testimony.

Mr. Malmgreen. Thank you.

Mr. Anthony. In the next panel we have Robert M. Reynolds, vice president of Shuler Drilling Co., John T. Lowery, Jr., partner, Lowery Oil Co., Lowe DeLone, partner, Maxwell Drilling Co., Inc. and DeLone Operating Co., Inc., and Kenneth E. Brasher, owner of Kebco Oil Co., all of whom are from my hometown of El Dorado, Ark. And I am sure Mr. Pickle is going to have something nice to say to you gentlemen.

My special thanks for not only coming to Washington to disclose the viewpoint of the independent oil producers and royalty owners from south Arkansas, but also for being very patient through a long day and suffering the consequences of being the last panel.

We have your written testimony. It will be accepted for the record in full, and you are free to proceed as you wish. You may read it, or summarize it.

## STATEMENT OF JOHN T. LOWERY, JR., PARTNER, LOWERY OIL CO., EL DORADO, ARK.

Mr. LOWERY. Thank you, Mr. Chairman.

For the record, I am John T. Lowery, Jr., partner in Lowery Oil Co., an independent oil producer, and if there is no objection, we will make a very brief statement. In light of the testimony given today, it will be very similar to what the committee has already heard.

I would like to testify on a grassroots level, if you will permit the term. Please permit me to give a brief background and history of how Lowery Oil Co. was formed.

My father, who formed the company, is 62 years of age. He worked for 21 years as an operator at the American Oil Refinery located in El Dorado. During those years, my mother worked in various grocery stores in order to supplement my dad's income.

My parents were first able to own a small business when they were able to buy a small neighborhood grocery store, where she had worked for a number of years. Later, they closed the small store and bought a larger convenience store.

The income derived from this store became our family's primary source of income when my dad took early retirement as a result of the closing of the refinery where he worked in 1971.

In the meantime, my father began to invest in the oil business in a small way. He began by buying half interest in two stripper wells. After obtaining a loan at a local bank, he bought the two wells and sold one well so he would have enough capital to buy the needed equipment to get the one back on production.

In time, he was able to buy half interest in other stripper leases. In April 1974, he was able to get into the oil business full time. In August of the same year, I went to work for my dad, and in June 1979, we became partners on a 50-50 basis.

Lowery Oil Co. is a small independent which only employs five people. But we contract work for such services as well servicing, well completing, and drilling. These companies employ as few as 6 and as many as 140 employees.

The oil industry is the leading industry in Union County in terms of total employment when you include all companies that are in some way related to the oil industry.

Any further loss of revenues to our industry at this time would have a devastating effect on the already high unemployment rate in our county and in south Arkansas.

Of the eight tax provisions that this committee is considering, the first two, depletion allowance and intangible drilling costs, give us, the small independent producers, the needed capital to drill and develop new leases, especially wildcats.

Simply stated, we will not be able to continue the drilling programs we have participated in in the past without these two tax provisions. Our drilling in 1981 and in 1982 resulted in an additional 80 barrels of oil per day to our company.

Even though we added the additional 80 barrels per day, our gross production has declined 4 percent since 1979.

Similarly, the total production of the State of Arkansas has also declined, as is shown in exhibit B, attached to my prepared testimony.

These figures were provided by the Arkansas Oil and Gas Commission.

The majority of the oil our company produces is stripper, considered heavy, 20 gravity or less, and has a high sulfur content. Most other independents in Union County also fall into this category.

The current posted price for this type of crude in our area is $25.10, which is contrary to the $30 and $29 a barrel oil we hear so much about.

These price postings are shown in exhibit C, attached to my testimony.

In exhibit D, I use this price to show the significance the windfall profit tax would have if put back on stripper oil. Currently, we have temporarily abandoned four leases that produced stripper oil because of the low price.

We would like to put these leases back on production, if the oil price stabilizes and increases. If the windfall profit tax exemption for independents is repealed or increased, not only would these leases be permanently abandoned, but we would have to consider abandoning more leases that are also marginal.

In conclusion, Lowery Oil Co. is a small independent that primarily produces stripper oil. It cannot exist if certain tax exemptions and provisions such as the one this subcommittee is reviewing are altered in a way that would prove detrimental to our industry.

[The prepared statement with attachments follow:]

## STATEMENT OF JOHN T. LOWERY, JR., LOWERY OIL CO.

The following written statement is presented by John T. Lowery, Jr., a partner in Lowery Oil Company, an independent oil producer. I reside at Route 5, Box 35-A, El Dorado, Arkansas. I was raised in El Dorado and received my education in the El Dorado Public School System and a Bachelor Degree in Business Administration from Southern Arkansas University in Magnolia, Arkansas, thirty miles west of El Dorado. Subsequent to my college education and a short term of work outside of the state, I have resided in El Dorado for the past eleven years. I am married and have three children aged eight, five and one years.

Before I go directly to the tax issues this committee is considering, permit me to give you a brief background and history of how Lowery Oil Company was formed. I feel this will allow you to better understand how these particular taxes or tax exemptions affect Lowery Oil Company on a day-to-day basis. My father, who is sixty-two years of age, has for the majority of his life worked in and around the El Dorado area. He worked shift work for twenty-one years as an operator for American Oil Company (Standard Oil of Indiana) until the refinery was closed in November, 1971. During those years my mother worked in various grocery stores in order to supplement my dad's income and help feed and clothe myself and my three sisters. My parents bought a small neighborhood grocery store in which my mother was employed when the owner decided to retire.

I helped by spending afternoons after school and Saturday mornings stocking shelves and delivering groceries on my bicycle until I was old enough to obtain a driver's license. After a number of years the neighborhood grocery store concept was fast losing ground to the convenience store and major supermarket chain. My parents closed their small store and bought a convenience store located in a small shopping center closer to downtown El Dorado. It was primarily my mother's responsibility to manage the store since my dad worked shifts at the refinery. The income derived from the store that was once a supplement became our primary source of income when my dad took early retirement as a result of the refinery closing. In the meantime, my father began to invest in the oil business in hopes that he could provide a better way of life for his family. He began by buying half-interest in two abandoned stripper wells with hope of putting them back on production. After obtaining a loan from the bank, he bought the two wells and sold one well so he would have enough capital to buy needed equipment to get the one well on production. In time he was able to buy half-interests in other stripper leases. In April of 1974 he fulfilled his dream of a fulltime oil business by making a successful bid on enough wells to do just that. In August of 1974 I went to work for my dad, and in June of 1979 we became partners on a fifty-fifty basis.

Now that you have a background of Lowery Oil Company, let me address some of the tax provisions this committee is considering that not only affect my dad, myself and both families, but also our five employees and their fourteen dependents as well. Although we may not be a large work force, we contract work for such services as drilling, well completing, well servicing, chemical applications, connection crews, etc. These services employ as few as six and as many as 140 employees. The oil industry is the leading industry in Union County in terms of employment. Any further loss of revenues to our industry would have a devastating effect on the already high unemployment rate in our county and South Arkansas.

The eight provisions of the Internal Revenue Code providing different tax treatment for different types of oil and gas producers will be adressed herein. The first three tax provisions listed in Press Release #4 will be grouped together for comparison purposes. Listed in attached Exhibit "A" are figures for 1981 and 1982 to help this Committee understand the importance of (1) percentage depletion allowance and (2) intangible drilling costs. Depletion allowance and intangible drilling costs give the small independent producer the needed capital to drill and develop new leases, especially wildcats, which lead to new reserves that are so vital to our industrialized nation and relieve us from the burden of imported oil. On an individual basis, Lowery Oil would not be able to continue the drilling program we have had in the past without these provisions. The drilling we undertook in 1981 and 1982 resulted in an additional eighty barrels of oil per day. Even as a result of these barrels added through drilling, Lowery Oil Company's gross production has declined four percent since 1979. Similarly, the total production of the State of Arkansas has also declined as shown in Exhibit "B" of the Addendum. Provision Three presents no particular problem to the independent producer as most are at risk for everything they invest in the drilling for, and production of, crude oil.

Provisions Four and Five concerning the reduced windfall profit tax rates for independents who produce 1,000 barrels per day and stripper exemption for independents are perhaps the most important items this Committee will address as far as this writer is concerned. The majority of the oil our Company produces is stripper - heavy (20 gravity or less) with a high sulphur content. Most other independents in Union County fall into this category. The current posted price for this type crude in this area is $25.10. I have enclosed two copies of current postings (see attached Exhibit "C") used by the two local refineries which purchase all our crude oil. Also enclosed please find figures (see attached Exhibit "D") using this price to show the significance the windfall profit tax will make in our ability to survive and grow. The windfall profit tax burdens the already suffering oil industry, and in our case, makes the difference in whether some leases are abandoned. Currently, Lowery Oil has temporarily abandoned four leases that produce stripper oil. We hope to put these leases back on production if and when the oil price stabilizes and increases.

If the windfall profits tax exemption for independents is repealed or increased, not only would these leases be permanently abandoned, but we would have to consider abandoning more leases that are marginal, to say the least, at the current oil prices. All of you are aware that the independent has virtually no "say" in the pricing of his product. The majors set the price they will pay for the crude they purchase. The major oil companies also have a means of passing on any tax to the consumer; whereas the independent has to absorb all his tax burden directly.

Provision Six citing the two barrel exemption for royalty owners does not affect Lowery Oil Company from the standpoint of our owning royalty as much as it affects us when we approach certain royalty owners about obtaining a lease. We run into the attitude such as "Why lease when the Federal Government will end up with more than I do?", or the royalty owners make the deal so tough the prospect has to be shelved.

In addressing Provisions Seven and Eight, there tend to be trade-offs in all segments of industry and the oil industry is not unique in that respect. Under Provision Seven corporations that are integrated oil companies may expense eighty-five percent of their intangible drilling expense and the remaining fifteen percent over thirty-six months; whereas, individuals and corporations that are independent producers may expense all of their intangible drilling costs. This leads back to the case of the major who can raise capital through the refining and marketing of consumer products and/or by selling stock, opposed to the independent who has a much more limited source of capital. Provision Eight states integrated oil companies must deposit their windfall profits tax faster than other taxpayers. This provision does not affect many independent producers since most have their windfall profit taxes withheld by the first purchaser.

In conclusion, Lowery Oil Company, as a small independent that primarily produces stripper oil, cannot exist if certain tax exemptions and provisions such as the ones this subcommittee is reviewing are altered in a way that would prove detrimental to our industry. If, in fact, we are able to survive, we could not enjoin in the ongoing quest to drill for oil and gas in our Country and help provide for this great Country's energy needs. Thank you for the opportunity to present this written testimony in behalf of some of the independent producers in South Arkansas.

EXHIBIT "B"

ARKANSAS
OIL AND GAS
COMMISSION

314 East Oak Street ● El Dorado, Arkansas 71730

Ph. 501 862-4965

William E. Wright
Director

April 29, 1983

Mr. John Lowery, Jr.
407 North Jackson
El Dorado, Arkansas 71730

Dear Mr. Lowery:

For your convenience and use we are attaching three bar graphs which dipict the total drilling permits issued, annual production and daily average production per well for the years 1973 through 1981. You will readily note that the highest annual production occurred in the years 1977 and 1978. Additionally, you will note that even though we had an increase of 500 wells drilled during 1981 as compared to 1977, the annual production was 1.5 million barrels of oil less than during the year 1977.

Annual production has been declining in the State since 1961 and even with the additional increase in exploration for energy reserves in Arkansas, the new reserves being discovered have not replaced the annual amount of oil being produced.

The average daily production per well has steadily declined since 1977. As will be noted on the bar graph, this daily decline in production has resulted in a daily average of 7.1 barrels of oil per day in 1977 and a daily average of 5.9 barrels of oil per day in 1981.

I trust that this data will be of service to you and if we may be of further assistance, please advise.

Yours very truly,

W. E. Wright

W. E. Wright, Director of
Production and Conservation

WEW:mt

enclosure

COMMISSION MEMBERS ● E. Boyd Alderson, Chairman, El Dorado
C. G. Davis, Vice Chairman, Magnolia ● Ned R. Price, Smackover ● James O. Staggs, Magnolia
Hayes C. McClerkin, Texarkana ● Spence A. Lemons, Fort Smith ● James C. Reynolds III, Camden

An Agency of the Arkansas Department of Commerce
An equal opportunity employer

## EXHIBIT "A"

The following figures are based on wells that Lowery Oil Company drilled either heads up (bore 100% of costs) or participated in. The dollar amounts used were dollars invested by Lowery Oil Company only and reflect only their interest.

| | TOTAL FOOTAGE DRILLED | DRY HOLE FOOTAGE | ADDITIONAL BBLS. DEVELOPED | DRY HOLE COSTS | WELL DEVELOPMENT | LEASE EQUIPMENT | UNDEVELOPED LEASEHOLDS | TOTALS |
|---|---|---|---|---|---|---|---|---|
| 1981 | 37,484 | 6,744 | 70 | $22,238 | $109,308 | $112,556 | $51,560 | $295,662 |
| 1982 | 24,490 | 18,602 | 10 | 89,895 | 67,964 | 32,410 | 25,366 | 215,635 |
| | 61,974* | 25,346* | 80 | $112,133 | $177,272 | $144,966 | $76,926 | $511,297 |

| | DEPLETION ALLOWED - BOTH PARTNERS (Before 65% limitation) | IDC AND DRY HOLE COSTS BOTH PARTNERS | TOTALS |
|---|---|---|---|
| 1981 | $100,536 | $131,546 | $232,082 |
| 1982 | 71,272 | 157,053 | 228,325 |
| | $171,808 | $286,599 | $460,407 |

* You will note that 41% of the footage drilled was dry which points up the high risk in oil exploration.

EXHIBIT "B"

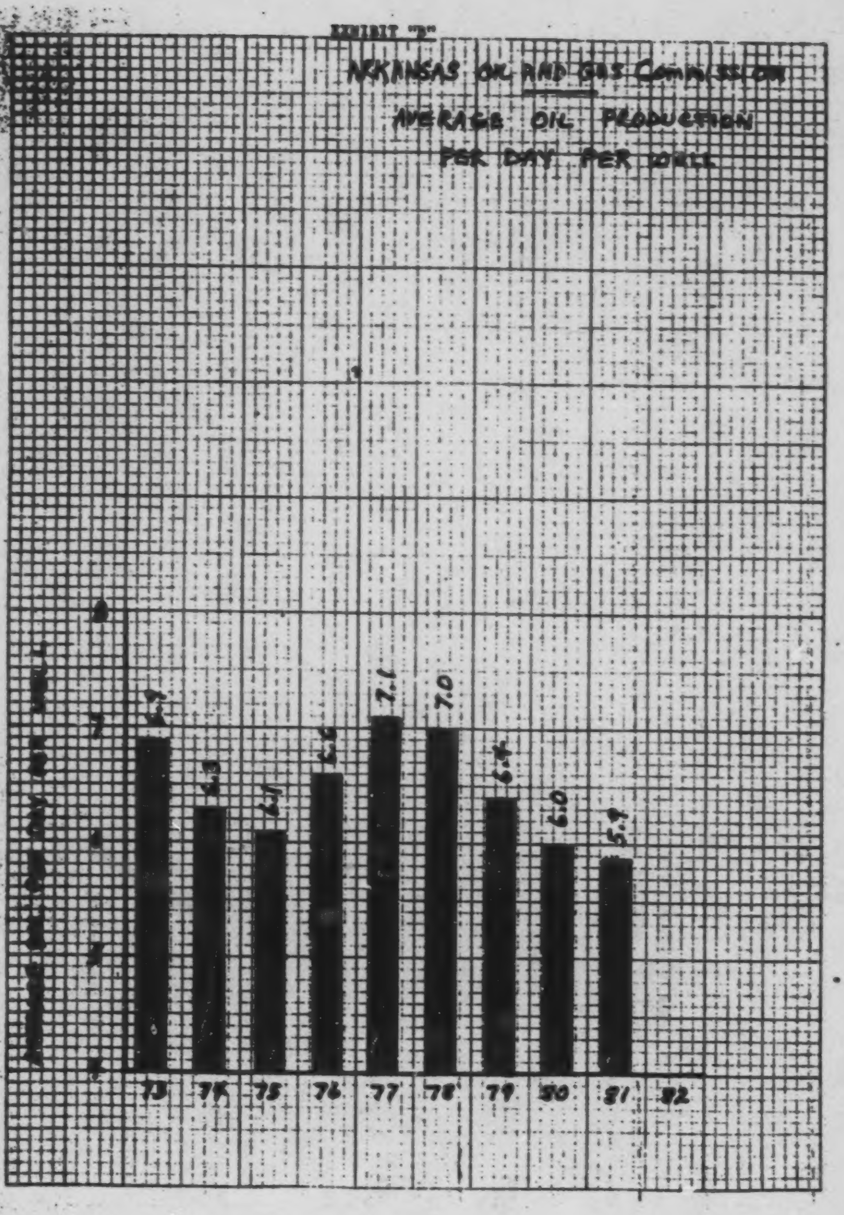
ARKANSAS OIL AND GAS COMMISSION
AVERAGE OIL PRODUCTION
PER DAY PER WELL
8
7
6
5
6.9
6.3
6.1
6.6
7.1
7.0
6.4
6.0
5.9
73
74
75
76
77
78
79
80
81
82

EXHIBIT "B"

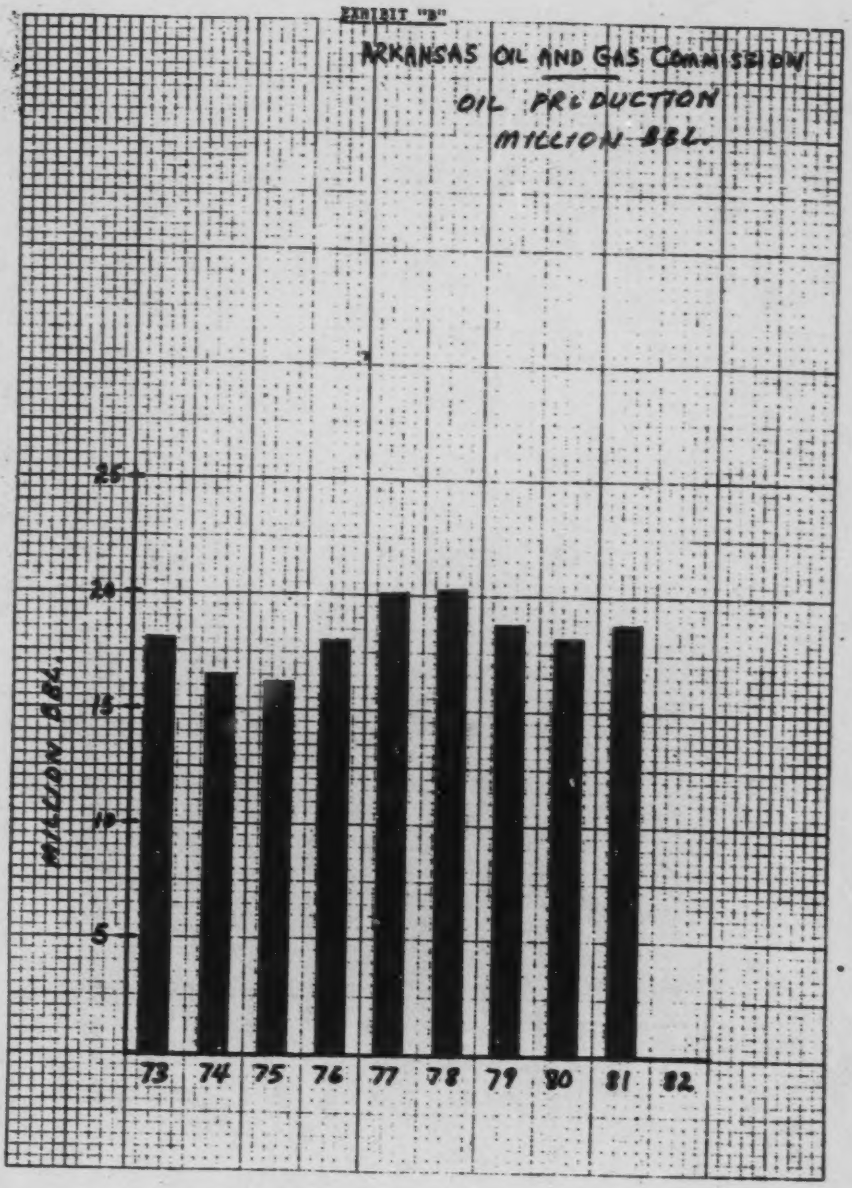
ARKANSAS OIL AND GAS COMMISSION
OIL PRODUCTION
MILLION BBL.
MILLION BBL.
25
20
15
10
5
73
74
75
76
77
78
79
80
81
82

EXHIBIT "B"

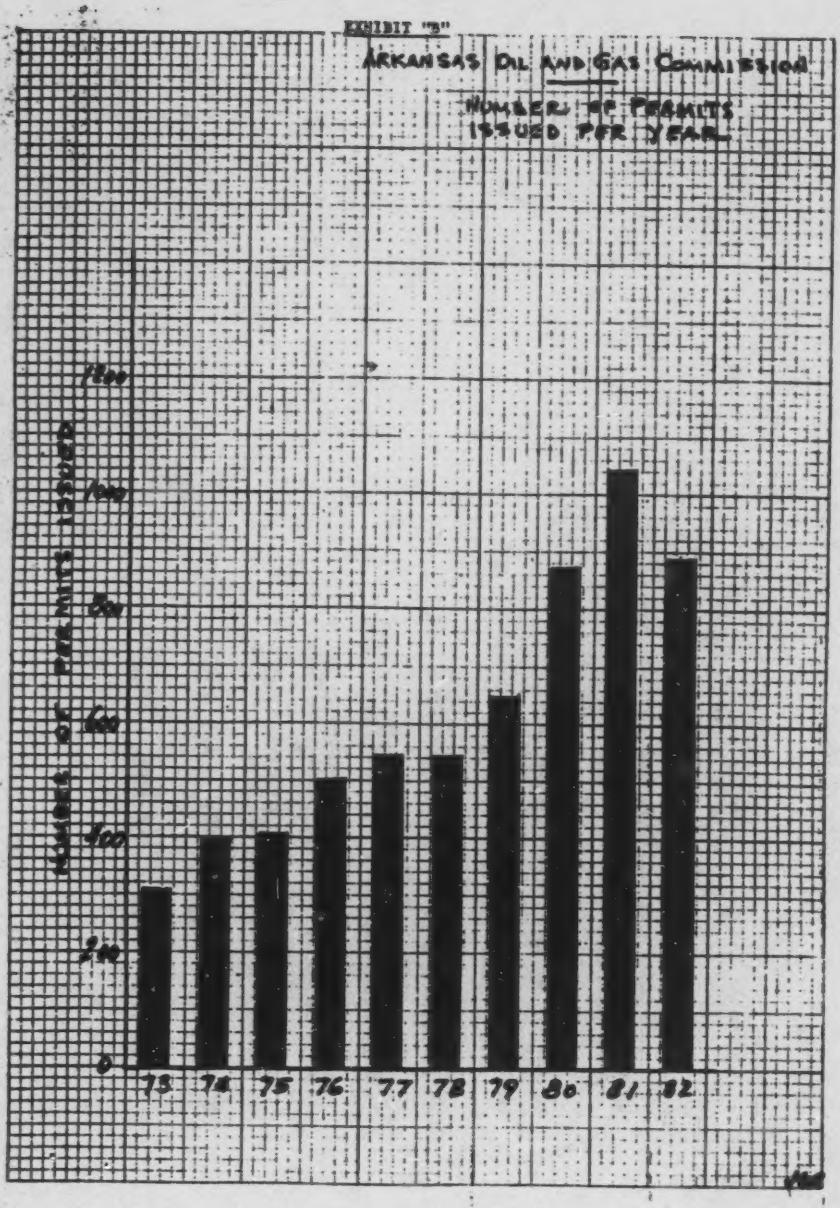
ARKANSAS OIL AND GAS COMMISSION
NUMBER OF PERMITS ISSUED PER YEAR
NUMBER OF PERMITS ISSUED
1200
1000
800
600
400
200
0
73
74
75
76
77
78
79
80
81
82

EXHIBIT "C"

# TOSCO CORPORATION

EL DORADO, ARKANSAS

Crude Oil Price Bulletin No. 220-B
April 15, 1983

Effective 7:00 A.M., April 16, 1983, subject to change without notice, TOSCO CORPORATION will pay the following prices per barrel of 42 U.S. gallons for merchantable Arkansas and North Louisiana crude oil purchased in Arkansas and North Louisiana and delivered to its account into the facilities of its authorized receiving agency. For crude oil transported by conveyance other than pipeline, TOSCO reserves the right to reduce the prices noted herein by an amount not exceeding the cost of such transportation.

| API GRAVITY | *SWEET CRUDE | **SOUR CRUDE |
|---|---|---|
| 40 - 44.9 | $30.00 | $29.00 |
| 39 - 39.9 | 29.98 | 28.85 |
| 38 - 38.9 | 29.96 | 28.70 |
| 37 - 37.9 | 29.94 | 28.55 |
| 36 - 36.9 | 29.92 | 28.40 |
| 35 - 35.9 | 29.90 | 28.25 |
| 34 - 34.9 | 29.88 | 28.10 |
| 33 - 33.9 | 29.86 | 27.95 |
| 32 - 32.9 | 29.84 | 27.65 |
| 31 - 31.9 | 29.82 | 27.35 |
| 30 - 30.9 | 29.80 | 27.05 |
| 29 - 29.9 | 29.78 | 26.75 |
| 28 - 28.9 | 29.76 | 26.45 |
| 27 - 27.9 | 29.74 | 26.15 |
| 26 - 26.9 | 29.72 | 25.85 |
| 25 - 25.9 | 29.70 | 25.55 |
| 24 - 24.9 | 29.68 | 25.10 |
| 23 - 23.9 | 29.66 | Below 24° 25.10 |
| 22 - 22.9 | 29.64 | |
| 21 - 21.9 | 29.62 | |
| 20 - 20.9 | 29.60 | |
| Below 20 | 29.58 | |

*Sweet crude is defined as having a sulphur content of .50 per cent or less by weight.

**Sour crude is defined as having a sulphur content in excess of .50 per cent by weight.

Crudes meeting TOSCO's acceptable lube crude specifications will be priced at 25¢ per barrel above postings noted herein.

The prices as posted are based upon computation of volume by using 100% tank tables, or as measured by approved automatic measuring equipment, and a deduction for all BS&W and correction for temperature deductions or allowances shall be made on the basis of 60° Fahrenheit temperature by use of Petroleum Measurement Table 6 ASTM D-1250. Crude oil purchased shall be free of contamination and/or alteration by foreign substances or chemicals not associated with virgin crude oil. These include, but are not restricted to, oxygenated and/or chlorinated compounds.

By accepting payment for crude oil purchased pursuant to the foregoing posting, each seller and payee certifies that he is in compliance with all laws, rules and regulations involved.

TOSCO reserves the right both to amend these prices and effective dates and to recover any payments made above those allowed through withholding payment from future settlements or by separate invoicing according to any applicable government regulations.

EXHIBIT "C"

**MACMILLAN PETROLEUM (ARKANSAS) INC.** P.O. BOX 1718 - 501 863-3191 - EL DORADO, ARK. 71730
PRODUCERS • REFINERS • MARKETERS -

## CRUDE OIL PRICE BULLETIN NO. 83-2

## CRUDE OIL PRICE BULLETIN

Effective 7:00 A.M., February 15, 1983, subject to change without notice Macmillan Petroleum (Arkansas) Inc. will pay the following prices per barrel of 42 U.S. Gallons crude oil, subject to the terms and conditions of its division orders and contracts:

| FIELD | FREE MARKET |
|---|---|
| SMACKOVER FIELD | $ 25.10 |
| CALION FIELD | 26.10 |
| CHAMPAGNOLLE LANDING FIELD | 25.10 |
| MUD LAKE FIELD | 25.10 |
| CROSS COUNTRY SLOUGH FIELD - ARTESIAN EAST FIELD | 25.10 |
| CHAMPAGNOLLE (RAINBOW), CYPRESS CREEK & BERRY | 25.10 |
| EL DORADO EAST - EZZELL AREA | 25.10 |
| RITCHIE FIELD & CRAIN CITY FIELD | 24.32 |
| CHARIVARI CREEK FIELD | 24.32 |

NOTE: MACMILLAN WILL PAY AN ADDITIONAL 25¢ PER BARREL FOR LUBE QUALITY CRUDE FROM THE ABOVE POSTED FIELDS.

All persons selling and receiving payment under this posting certify the correctness of such price under the applicable regulations; however, in the event a seller is unable to accept the prices established in this bulletin, it shall be his responsibility to certify to Macmillan Petroleum (Arkansas) Inc., in writing, the price which he is permitted to accept.

If changes are made in Federal Price Regulations or their application which retroactively limit either the price Macmillan can pay or the effective date of these prices, Macmillan reserves the right both to amend these prices and effective dates accordingly and to recover any payments from future settlements or by separate invoicing.

2/15/83

## EXHIBIT "D"

## INCOME AND COSTS PER BARREL

| | | | |
|---|---|---|---|
| Current Posted Price | $25.10 | | |
| Severance tax 4% | -1.00 | | |
| Special state tax | - .045 | | |
| Net Price | | $24.05 | |
| Lifting Costs | $12.05 | | |
| Administrative Costs, Interest, etc. | 6.19 | | |
| Well Development Costs | 4.19 | | |
| Net Costs | | -22.43 | |
| Net per barrel for partners' salaries, profit, and future well development | | | $1.62 |

**If windfall profit tax was implemented on stripper oil:**

| | | |
|---|---|---|
| $25.10 | with base 13.83 for Tier II x inflation adjustment factor | |
| -17.81 | taxable | |
| 7.29 | windfall profit | |
| -.29 | (based on severance tax-4% allowed) | |
| 7.00 | x 30% for independent producer | |
| $2.10 | Windfall Profit Tax Per Barrel | -2.10 |

DEFICIT - If windfall profit tax exemption is repealled -(.48)

Mr. **Anthony**. Mr. Lowery, before we go to the next witness, you had an exhibit that I thought was very interesting, and I made sure that the chairman of the subcommittee looked over your testimony before he had to depart for New York for other business. You had an exhibit that talked about the present marginal well and the implications that would occur if tax exemptions were repealed this year. I think the comments that the chairman made today were important and I also observed his points were not made by anyone else.

I want to thank you for bringing out in a very graphic and grassroots way, as you say, from a producer standpoint, that tax policy can create energy policy, and here is an opportunity for us to help a national emergency circumstance if we will only pursue a rational tax policy.

I want to thank you for bringing out those figures in your testimony.

Mr. Pickle indicated earlier that he was going to circulate the testimony and see to it that other members of the committee, as well as the staff, take a look at this even though they are not present.

I think this will go a long way in helping us establish the type of record we were hopeful we could establish. I think it is a very valuable contribution, and I thank you for doing that.

Mr. **Pickle**. I want to add, too, Mr. Lowery, you are a small operator, and I guess, of the people who have testified today, you and the other fellows on this panel are the smallest. But there are a lot of them throughout the country.

You said you are small, these tax laws are not just something frivolous, they are just as necessary for you as a big company and if you didn't have depletion, didn't have the IDC, you wouldn't be in business.

Mr. **Lowery**. That is right.

Mr. **Pickle**. Is that basically correct?

Mr. **Lowery**. That is correct. We have to have that source of capital, if you will, since we do not refine products and do not have access to capital that the majors do, such as issuance of stocks, et cetera. This is what we use to continue our drilling, and we use some of those moneys—that is, some of that capital derived from depletion allowance and IDC's—toward existing wells that are very marginal at the current price, and with the windfall profit tax attached.

A lot of times we drill wells that are stripper to begin with, but because of the way the stripper exemption is set up, we have to operate those for 12 months before we get that exemption.

So, even though they may produce 10 barrels a day or less, initially, we still are taxed as new production until the 12-month period.

Mr. **Anthony**. Mr. DeLone, would you like to go next?

## STATEMENT OF STOWE DeLONE, PARTNER, MAXWELL DRILLING CO., INC., DeLONE OPERATING CO., INC., EL DORADO, ARK.

Mr. **DeLone**. Thank you, Mr. Chairman, for allowing us to speak here today. I will be very brief, since we have all been here a long time, and much of the information will be repetitive.

I would like to go along with what Mr. Lowery said as to some of these stripper wells we have been producing. Were it not for the depletion allowances, the IDC that we have, many of these wells in the range of 2 to 5 barrels would not be drilled and many of these are still being drilled in south Arkansas.

We are unique in the sense, I suppose, that we have had producing fields since the early 1920's, and many of these wells are still producing today. I know in our case, the wells that we operate, we are operating in a field that was producing, has been producing constantly since 1921.

So, most of these, at least six or seven of the wells that we operate, are wells that have been producing with no lengthy downtime since 1921.

So you can see the years involved and the equipment involved over all these years.

We have gone back into these old fields and have done real well in drilling new wells. We have currently drilled approximately, I would say, 25 to 30 new wells in this old area and our production itself, and when I say we have drilled 30 wells, these have not been for ourselves, or at least all of them have not been for ourselves.

We have added approximately 80 to 100 barrels of production within the last 8 to 10 months in these old fields which were largely abandoned by the major companies in the early thirties, because there were larger fields and larger finds to be had in east Texas and other places that were finding commercial production.

These things, I think, are important not only to us in our community, of course. Certainly, as you well know, Mr. Chairman, in south Arkansas, the oil industry and the timber industry certainly are the basis for all of our economy, and were it not for the fact that we had these old fields and people that produce this stripper oil, the economy would certainly look bleak.

The timber business, as you well know, has been down, but our oil business has largely kept the economy on stable ground until here lately, when the number of rigs that are drilling wells has drastically been reduced.

We have three rigs in the past that have been running full time. This year, or last year, and so far this year, we have only been running possibly, as I said, we have only been running, probably, as I said, we have three, and two of them have been running some time, one of them has been running most of the time; so, from that standpoint, you can tell how many people, there are approximately 15 people, give or take 1 or 2, that works on each rig, so, with only one rig running full time, out of three, you can see how much unemployment that adds up to be.

So all of these things are problems, not only in our community, but you have heard from all of the other representatives that have been here from the oil industry and certainly, our position and our situation is no different than theirs.

Our production is no different than theirs, not being familiar with that, we know our problems and we know that is a problem to produce the stripper oil.

So, we need these tax incentives. There is no question about it. We would not be doing the things that we have been doing if it were not for the breaks that we are getting. It is just not possible to do.

It all comes down to the bottom line of economics, and it is no different than any other business. Your small producers, just like your small businessman, he has to have certain incentives, whether it be—whatever it might be—we did not control our prices, therefore, it costs. We have our prices dictated to us, so we do have no say-so over the prices.

So, whatever it costs us, we are locked in at the top figures as to what we are going to get for our oil.

So, to be very, very careful to see that we are operating very efficiently and this, of course, is what it is all about, anyway.

One other thing that I would like to say is that I think Congress was very wise in granting us these exemptions, and I think probably, had we not had them, certainly we would not have been able to maintain what we have had today.

I would like to say and point out just since this committee or subcommittee—the information on this subcommittee has been released, there have been many, many people that—I say many, several people that have come in, that were planning on drilling wells, that have more or less backed out of it at the present time, they have taken a wait-and-see attitude to see what the Congress is going to do in regard to the small independent operators.

So, it does have a detrimental effect. As I said, we have heard from many people today, and there have been questions from the podium as to what is this going to do or that going to do, why it would be necessary to be so.

We all know that when, as I said before, when economics are not there, we just cannot operate.

So, in summation, the exemptions that we had have been probably the most important thing that the small, independent producer could have had in the last year or so, so I certainly would hate for us to back up at this particular point, because we certainly are not in a position to take any more cuts. It is just not feasible at this time.

Thank you very much, Mr. Chairman.

[The prepared statement follows:]

### STATEMENT OF M. S. DELONE, JR., MAXWELL DRILLING CO., INC., DELONE OPERATING CO., INC.

The subject of this statement relates to the Subcommittees' review of the different tax treatment for different types of oil and gas producers. The terms of which are outlined in PR No. 4 and released for informative purposes. This statements purpose is to show the need for this differential treatment and why it is essential to the independent oil producer.

(1) An independent producer (i.e., one who does not refine or retail more than a certain amount) may claim percentage depletion on up to 1,000 barrels of oil per day or the equivalent amount of natural gas.

Depletion in some form has remained in effect for many years. The laws governing depletion allowances have characteristically been the most complex of the tax laws. These were enacted to allow reasonable deductions for diminishing or depletable resources such as mines, oil and gas wells, timber, and other natural deposits.

Major companies are not now allowed a depletion allowance whereas the independent is allowed to deduct 75 percent of the gross income to the extent that the figure does not exceed 50 percent of the taxable net income of the property.

The independent oil producer has long been the leader in the number of wells drilled throughout the country. The typical figures project the independent as drilling 85 percent to 90 percent ot the discoveries of new oil. This figure would certainly hold true in South Arkansas where few of the major companies chose to explore. Were it not for the depletion allowances given to these independents many of the small fields would not be found or developed to the fullest extent. In the area of South Arkansas many wells are still being drilled in the 2-5 barrel range by small operators. The drilling of these "marginal" producers certainly spurs the economy of the area creating jobs not only in the drilling business but also the multiples of the supply and service business of the oil industry. The point being that the larger companies are certainly not in the habit of drilling wells in this production range. (Their break even point would be somewhere in the 12-15 barrel range according to certain factors.)

If we are ever going to cease being energy dependent, and we certainly are nowhere near that point at this time, the small independent must assuredly take the leadership role in this committment. Added incentives can only make him more aggressive to achieve this goal. The pluses in achieving sufficient energy for the future means maintaining the present jobs and adding new ones which is not only important for our community but the nation as a whole. Independent producers, although at the forefront in the exploration field, continue to be at the mercy of the large oil companies in that the independent cannot price his product as other business can. He must sell his oil at whatever price the major companies dictate. Unlike other business, who can create their own product prices in accordance with their related costs, the independent is "locked in" not knowing from month to month what his product will be worth. This is especially true in South Arkansas where the prices have been from 1-2 dollars lower than the surrounding states for equivalent crude oil. This only heightens our predicament as independents to find the capital to fund our exploration.

(2) Intangible drilling costs (IDC'S) of individuals (but not corporations) are subject to the 20 percent alternative minimum tax. However, individuals may elect to write off their IDC'S over 5 years and claim the investment tax credit, in which case the IDC'S are not subject to the minimum tax.

(3) Intangible drilling costs of individuals and closely held corporations (but not widely held corporations) are subject to the at-risk rules.

(7) Corporations who are integrated oil companies may expense 85 percent of their intangible drilling costs. The remaining 15 percent is to be written off over 36 months. Individuals and corporations who are independent producers may expense all of their IDC'S.

Since these three provisions deal with IDC'S they are grouped together. For clarification, IDC'S are defined as expenditures made by an operator for wages, fuel, repairs, hauling and supplies, etc., incident to and necessary for the drilling of wells for the production of oil and gas.

A comparison of the major versus independent as to IDC'S would be somewhat repetitive in this section since the same factors previously mentioned are still in effect. No control of crude pricing, limited capital, small lot purchasing of equipment and supplies, and limited geographical areas tend to put the independent producer in the back seat in the competition for new oil discoveries. Yet the independent continues to be in the forefront of drilling activity. To allow this to remain so, tax deductions in the form of IDC'S are necessary and only serve to produce more jobs in the oil field and related areas.

The outlook for the independent producers and small drilling company of which I am a part owner has been dismal this past year of 1982. Our work force has been cut back by approximately 50 percent. Where in 1981 we were operating three rigs, today we are operating two and a majority of the time only one. With an average of fifteen men to a rig it is not hard to project the unemployment involved and without tax inducements it would no doubt be a more grave situation.

(4) Up to 1,000 barrels per day of crude oil produced by an independent producer are eligible for reduced windfall profit tax rates from 70 to 50 percent on tier one and from 60 to 30 percent on tier two.

(5) Stripper oil produced by independent producers is exempt from the windfall profits tax.

These two provisions having to do with pricing will be grouped together. These two provisions, of the entire eight, are the most important to the independent producer. Stripper oil came into proiminence during the Arab oil embargo in 1973 when it was realized that many small, marginal, or stripper wells were much more important to the national energy picture than previously thought. A given figure of 10 barrels per day or less was used to determine stripper production at that time and this definition stands today. As has been mentioned before, the break even point for the major companies is somewhat above ten barrels so this leaves the burden of producing these stripper wells to the independent. Most areas with production this low have been abanonded by the majors or sold to small producers after the "flush" production is gone.

Our small company currently operates six wells that were drilled in 1921 South of El Dorado, Arkansas. They have been producing basically without any lengthy shutdown since that year. Hunt Oil Company, Carter Oil Company, Standard Oil Company are just a few of the large companies who drilled and operated this field until the boom in East Texas provided better opportunity to find larger producing wells.

For us to operate these wells commerically we must handle large volumes of water of recover only a small amount of oil. This means heavy pumping equipment, driven at high speeds, must be used to extract this oil. This in turn means more costly recoverable oil due to equipment breakdown and high replacement costs. Were it not for the windfall tax exemption given to stripper production wells could not be feasibly operated. Even with this exemption, lower crude prices have made many small wells impractical to operate. This exemption was the wisest step Congress could have taken in securing a future for these small stripper wells.

(6) Up to 2 barrels per day of oil production of qualified royalty owners are exempt from the windfall profit tax (3 barrels per day after 1984).

The provision partially corrected what was probably the unfairest tax of all, that of the tax on the royalty owners. The majority of the royalty owners in South Arkansas are small landowners or recipients of minute family holdings passed down through generations and split many times among the heirs of certain tracts. Very few have ever gotten "rich" due to their royalty income and for most this is only a supplement to a meager income.

(8) Integrated oil companies must deposit their windfall profit tax faster than other taxpayers.

This provision provides that the integrated oil companies as first purchaser must deposit with the federal government the tax which is withheld from the sale of crude oil. This provision really has no bearing on the independent producer.

The Congress of the United States must be commended for using discretion when dealing with the differences between major oil companies and independent producers. Much of the evidence given in this statement has been heard before or Congress would not have seen fit to grant these tax deductions to begin with. The situation in regard to independent producers is certainly even more critical today than it was when these tax deductions were voted upon. Drilling rigs idle, high unemployment, lower oil prices, less investment money in the economy lends creedence to the notion that the independent needs no more burden to restrict his already curtailed exploration and development of new oil fields.

Independents are involved in the economic and civic affairs of the community and wish to remain in the forefront of creating new jobs to aid the economy.

Mr. ANTHONY. Thank you.

## STATEMENT OF ROBERT M. REYNOLDS, VICE PRESIDENT, SHULER DRILLING CO., INC., EL DORADO, ARK.

Mr. REYNOLDS. Thank you, Mr. Chairman.

I am Robert Reynolds, an engineer with Shuler Drilling Co. We are an oil well drilling contractor who work primarily for independent oil and gas operators. I am a third generation on both sides of the family to work in the petroleum industry in different capacities. Some family members worked for majors, as roustabouts, engineers, and so forth.

What I would like to pass along is my observations about the differences between independent producers and majors. Since we do work for both, I see both.

As in any industry where both large and small businesses exist, there tend to be economies of scale enjoyed by the larger and lacked by the smaller.

Over a long period of time most heavy industries undergo a consolidation process whereby the large become larger and fewer through acquisition, merger, and failure of the smaller enterprises. For example, automobiles, steel, aircraft.

Historically, only a partial consolidation has occurred in the oil producing industry. In fact, a reverse process occurs sporadically as employees of larger oil producers leave to establish themselves as independent producers.

The smaller segment of the industry actually resists consolidation with the larger and provides effective competition to the larger, so effective, in fact, that a 90-percent majority of domestic onshore exploratory drilling is done by independent producers who control only a minor fraction of actual production.

The leadership of independent wildcatters who take the greatest risks actually searching for new oil reservoirs is maintained by the independent producers, not by the slower moving, more bureaucratic larger organizations.

Discovery of additional domestic reserves is important from a national standpoint and is best served by a viable independent sector.

Decreasing incentives to independent producers will lead to a gradual domination by fewer, larger firms. The greatest existing advantage now had by major producers is that they are also the primary purchasers of independents' crude oil.

The independents' leadership in the industry ends at the pipeline and does not reappear at the refinery or the gasoline pump.

The past year has witnessed the sharpest decline in domestic drilling activity since the Great Depression. At the end of 1981, 4,530 drilling rigs were running and by October 1982, only 2,379 drilling rigs were working, a decline of 47 percent in just 10 months.

Today, the picture is even gloomier with only 1,834 rigs looking for oil and gas. This represents unused capacity of 60 percent and concomitant unemployment.

The drilling company for whom I work employed 140 people at the end of 1981 and employs 110 today due to one-third of its rig fleet being idle.

There are several reasons for the curtailment of U.S. drilling activity, including the worldwide recession and OPEC-induced oil glut and gas bubble.

As long as a third of domestic oil consumption still comes from imported crude, the glut is illusory. Reduction of incentives by increasing the tax burden will cause further curtailment of exploration activity and increase unemployment in an industry that has already dropped far below the employment levels of the general economy.

In 1980, we drilled 136 wells on contract; 206 in 1981; 174 in 1982; project 150 in 1983. In 1980, the industry drilled 64,847; 80,642 in 1981; 86,933 in 1982; project 70,000 in 1983.

Present tax law recognizes the economies of scale within the oil producing industry and affords smaller producers a lesser hurdle to pass along to the eventual consumer.

What is not recognized by the law is the province of operations. The typical independent oil producer in south Arkansas is operating in an area which was given up by major oil producers in the 1930's.

Some independents operate wells that were abandoned as uneconomical by majors years ago. Except for large fields which continue to produce, the major oil companies terminated their exploration activites in south Arkansas long ago.

Independent operators make their living on the slim pickings left by the majors, mostly on the flanks of old fields, from reservoirs related geologically but not necessarily directly in communication with the main field reservoirs.

Oil was discovered in Arkansas by an independent wildcatter in 1921, majors swooped in and bought large blocks of acreage, developed the acreage, then focused their attention elswhere, leaving behind a number of mostly local independents. The same scenario has been played out numerous times all across the country.

The stripper well, one which produces less than 10 barrels per day, is also the almost exclusive province of the independent producer. The 10-barrels-per-day criterion is arbitrary, although reasonable for a well which produces such a small volume of oil that the gross income therefrom provides only a small margin of profit or, in some cases does not even cover the actual cost of production.

Thank you, Mr. Chairman.

Mr. ANTHONY. Thank you very much.

[The prepared statement follows:]

## STATEMENT OF ROBERT M. REYNOLDS, SHULER DRILLING CO., INC.

The Subcommittee will review the effects of differences in the tax treatment of various types of oil and gas producers. This statement will address the provisions of the Internal Revenue Code which provide different tax treatment for different types of oil and gas producers in the form outlined by PR No. 4, from the standpoint of the oil and gas industry in South Arkansas.

(1) An independent producer (i.e., one who does not refine or retail more than a certain amount) may claim percentage depletion on up to 1,000 barrels of oil per day or the equivalent amount of natural gas.

Depletion for tax purposes is the removal and sale of minerals from a mineral deposit. The tax concept of depletion differs from the physical and economic concepts in that the former depends on sale and the latter only on removal.

Independent oil and gas producers are allowed to deduct an arbitrary 15 percent of gross income, if such figure does not exceed 50 percent of the taxable net income of the property, in a fashion similar to other non-renewable mineral resource producers, such as coal.

As in any industry where both large and small businesses exist, there tend to be economies of scale enjoyed by the larger and lacked by the smaller. Over a long period of time, most heavy industries undergo a consolidation process whereby the large become larger and fewer through acquisition, merger, and failure of the smaller enterprises (for example, automobiles, steel, aircraft). Historically only a partial consolidation has occurred in the oil producing industry. In fact, a reverse process occurs sporadically as employees of larger oil producers leave to establish themselves as independent producers. The smaller segment of the industry actually resists consolidation with the larger and provides effective competition to the larger, so effective, in fact, that a 90 percent majority of domestic on-shore new oil discoveries are made by independent producers who control only a minor fraction of actual production.

The leadership of independent "wildcatters" who take the greatest risks actually searching for new oil reservoirs is maintained by the independent producers, not by the slower-moving, more bureaucratic larger organizations. Discovery of additional domestic reserves is important from a national standpoint and is best served by a viable independent sector. Decreasing incentives to independent producers will lead to a gradual domination by fewer, larger firms. The greatest existing advantage now had by major producers is that they are also the primary purchasers of independents' crude oil. The independents' leadership in the industry ends at the pipeline and does not reappear at the refinery or the gasoline pump.

(2) Intangible drilling costs (IDC's) of individuals (but not corporations) are subject to the 20-percent alternative minimum tax. However, individuals may elect to write off their IDC's over 5 years and claim the investment tax credit, in which case the IDC's are not subject to the minimum tax.

(3) Intangible drilling costs of individuals and closely held corporations (but not widely held corporations) are subject to the at-risk rules.

(7) Corporations who are integrated oil companies may expense 85 percent of their intangible drilling costs. The remaining 15 percent is to be written off over 36 months. Individuals and corporations who are independent producers may expense all of their IDC's.

These three provisions will be treated together since they are related. Intangible drilling and development costs are expenditures incurred by an oil producer for labor, fuel, repairs, hauling, and consummable supplies used in drilling, perforating, and cleaning of wells; in preparing the surface for drilling and in the construction of tanks, pipelines, and other structures used in connection with producing but not including the cost of the materials themselves. The fundamental test is, do the items have salvage value? If not, they qualify as intangibles. The issue of independent versus major has been addressed previously in item (1) and applies in the same manner with regard to intangible drilling costs.

The issue of writing off intangible drilling costs is analagous to the accelerated depreciation of capital equipment in capital intensive industries, such as automobiles and steel. If automakers and steel makers were not able to depreciate their equipment for tax purposes, they would face even greater obstacles in modernizing their plants. If oil producers were not able to expense their service intensive costs in a similar manner, their after-tax cost of drilling and equipping new wells would increase.

The past year has witnessed the sharpest decline in domestic drilling activity since the great depression. At the end of 1981, 4530 drilling rigs were running and by October of 1982, only 2379 drilling rigs were working, a decline of 47 percent in just ten months. Today, the picture is even gloomier with only 1834 rigs looking for oil and gas. This represents unused capacity of 60 percent concommitant unemployment. The drilling company for whom I work employed 140 people at the end of 1981 and employs 110 today, due to one-third of its rig fleet being idle.

There are several reasons for the curtailment of U.S. drilling activity, including the worldwide recession and OPEC-induced oil "glut" and gas "bubble". As long as a third of domestic oil consumption still comes from imported crude, the "glut" is illusory. Reduction of incentives by increasing the tax burden will cause further curtailment of exploration activity and increase unemployment in an industry that has already dropped far below the employment levels of the general economy. In 1980 we drilled 136 wells on contract; 206 in 1981; 174 in 1982; project 150 in 1983. In 1980 the industry drilled 64,847; 80,642 in 1981; 86,933 in 1982; project 70,000 in 1983.

(4) Up to 1000 barrels per day of crude oil produced by an independent producer are eligible for reduced windfall profit tax rates (from 70 to 50 percent on tier 1 and from 60 to 30 percent on tier 2).

(5) Stripper oil produced by independent producers is exempt from the windfall profit tax.

These two provisions will be treated together since (5) is an extension of (4). The "windfall profit" tax is an excise tax levied at the wellhead, which is passed from producer to transporter to refiner to marketer to consumer, like any other excise tax, such as the one on tires. Present tax law recognizes the economies of scale within the oil producing industry and affords smaller producers a lesser hurdle to pass along to the eventual consumer.

What is not recognized by the law is the province of operations. The typical independent oil producer in south Arkansas is operatng in an area which was given up by major oil producers in the 1930's. Some independents operate wells that were abandoned as uneconomical by majors years ago. Except for large fields which continue to produce, the major oil companies terminated their exploration activities in south Arkansas long ago. Independent operators make their living on the slim pickings left by the majors, mostly on the flanks of old fields, from reservoirs related geologically but not necessarily directly in communication with the main field reservoirs. Oil was discovered in Arkansas by an independent wildcatter in 1921, majors swopped in and bought large blocks of acreage, developed the acreage, then focused their attention elsewhere, leaving behind a number of mostly local independents. The same scenario has been played out numerous times all across the country.

The stripper well (one which produces less than 10 barrels per day) is also the almost exclusive province of the independent producer. The 10 barrels per day criterion is arbitrary, although reasonable for a well which produces such a small volume of oil that the gross income therefrom provides only a small margin of profit or, in some cases does not even cover the actual cost of production.

(6) Up to 2 barrels per day of oil production of qualified royalty owners are exempt from the windfall profit tax (3 barrels per day after 1984).

This provision in the amended windfall profit tax legislation recognized the least person of all—the private landowner whose property happened to contain oil in commercial quantities. The original treatment of private landowners in the act of 1980 was the greatest example of blindness in that piece of legislation. The amendment of 1981 corrected one-half of the injustice, but the royalty owner is still stuck with a tax whose theory is based on factors completely out of the realm of the private landowner. The private landowner still pays unearned income tax on the royalty payments he receives, regardless of whether the amount of royalty is influenced by any "windfall".

(8) Integrated oil companies must deposit their windfall profit tax faster than other taxpayers.

This provision recognizes that integrated oil companies are the predominant purchasers of crude oil, regardless of who produces it. The law charges the first purchaser of crude oil with the responsibility for withholding and transmitting the tax to the federal government.

Mr. Anthony. Mr. Kenneth Brasher.

## STATEMENT OF KENNETH E. BRASHER, OWNER, KEBCO OIL CO., EL DORADO, ARK.

Mr. Brasher. Thank you, Mr. Chairman. I am Ken Brasher. I was not raised in the oil business, but I have been in the industry for the last 8 years.

I work for my father-in-law and my wife's grandfather. They have been in the oil business for the last 45 years.

I started out working in the oil fields as your basic roustabout, one who services the wells. Then I moved up to a pumper, one who checks the wells and gages the tanks. Presently, my job is still as a pumper, but I am second in command over the two gangs we employ.

Independent producer oil is oil on which a reduced rate is allowed with respect to the windfall profit tax for tiers 1 and 2. Independent producer oil is the portion of an independent producer's qualified production for the quarter which doesn't exceed his independent producer amount for the quarter.

I have stripper oil production of my own and therefore I feel I can evaluate these provisions from the standpoint of an employee and also as an independent producer.

As an employee and independent producer, I know from experience what these exemptions, if they were put back into law, would mean to me and my family's future in the oil business.

All of us are young men in the oil business. We are here mainly to represent our futures in this business. We were introduced earlier today as second and third generation oil producers.

I would like to see one of these days where there might be third and fourth, fifth, and sixth generations in our business.

If these exemptions were put back into effect, it would have a devastating effect on my business and my in-laws' business.

We have already, at this point, taken away overtime days for some of our employees. This has hurt them because they are out there week after week just drawing a paycheck. If it gets any worse, we might have to lay off some gangs.

At this point we are just getting by.

I hope that we can keep these exemptions for the oil business in southern Arkansas.

[The prepared statement follows:]

### STATEMENT OF KENNETH E. BRASHER, KEBO OIL CO.

The following statement is by Kenneth Brasher. I was not raised in the oil business and have only been subject to this industry for the last eight years. I have a wife, Connie and two children, Keb age four years and Bendy, age one year. I work for my father-in-law and my wife's grandfather. They are in the oil business and have been for forty five years.

I started out working in the oil fields as your basic roustabout, one who services the wells. Then I moved up to a pumper, one who checks the wells and gauges the tanks. Presently, my job is still as a pumper, but I am second in command over the two gangs we employ.

Independent producer oil is oil on which a reduced rate is allowed with respect to the Windfall Profit Tax for Tiers 1 and 2. Independent producer oil is the portion of an independents producer's qualified production for the quarter which doesn't exceed his independent producer amount for the quarter.

I have stripper oil production of my own and therefore, I feel I can evaluate these provisions from the standpoint of an employee and also as an independent producer. As an employee and independent producer I know from experience what these exemptions, if they were put back into law, would mean to me and my family's future in the oil business.

The subject of this statement relates mainly to the tax treatment of different types of oil and gas producers. I personally will only deal with five of the eight provisions, because these five are the ones that effect me personally in my business.

(3) Intangible drilling costs of individuals and closely held corporations (but not widely held corporations) are subject to the at-risk rules.

Intangible drilling costs are spending made by an operator for wages, fuel, repairs and supplies necessary for drilling of wells for the production of oil and gas. This provision presents no particular problem to the independent because they are at risk for everything they invest in the production or for that matter the drilling for crude oil.

(4) Up to 1,000 barrels per day of crude oil produced by an independent producer are eligible for reduced Windfall Profit Tax rates (from 70 to 50 percent on Tier 1 and 60 to 30 percent on Tier 2).

(5) Stripper oil produced by independent producers is exempt from the Windfall Profit Tax.

Stripper oil is oil produced from a property from which the average daily per well production has been 10 barrels or less for any consecutive 12 month period after 1972. Stripper oil is in Tier 2 of the Windfall Profit Tax and generally is subject to a 60 percent rate of tax. However, independent producers are eligible for reduced Windfall Profit Tax rates on up to 1,000 barrels a day of Tier 1 and Tier 2 oil. The reduced rate applicable to an independent producer's Tier 2 oil is 30 percent rather than 60 percent.

These provisions are perhaps the most important to the independent oil producer, as far as I am concerned, because the majority of our oil is a heavy stripper (20 gravity or less with a high sulfur content). As of January 1, 1983 stripper oil became exempt from the Windfall Profit Tax, this has enabled us additional capital from the oil prices to reinvest in oil production such as drilling, new exploration and workovers that will lengthen the productivity of all stripper wells. If the Windfall Profit Tax was put back into effect in my case, on one particular lease, we would probably have to shut down or temporarily abandon this lease, because we are operating at this point at a break even situation. At this time, I can afford to operate in this manner, because the oil production is not my only source of income. It would however, effect my income because of the oil company for whom I work. The oil company I work for has shut down several leases because the drop in oil prices, have proven to be non-profitable to operate. If the tax was put back into effect, they would permanently be shut down along with several more leases. Another thing I wish to bring out in this statement is that the major oil companies set the price they will pay for crude which they purchase. The majors also have the means of passing on any tax to the consumer, whereas the independent has to absorb all his tax burdens directly and as an independent pays it on the consumer end also.

(6) Up to 2 barrels per day of oil production of qualified royalty owners are exempt from the Windfall Profit Tax (3 barrels per day after 1984).

This provision really does not apply to me personally, the reason is I have not had to encounter land owners as of yet in my production. But, I would like to say that so many of the land owners of Southern Arkansas are on fixed income, and whose property just so happened to contain oil, with additional tax they are unable to pay the burden of the tax put on them for owning this land. A very small number of royalty owners have never gotten rich due to their royalty income. It also makes it hard for an independent oil producer, such as myself, when if ever I were to go to a land owner to try to obtain a lease.

(8) Integrated oil companies must deposit their Windfall Profit Tax faster than other taxpayers.

This provision really has no bearing on the independent oil producer other than, when we sell our oil to the refineries. The refineries pay this tax with the money that would originally be owed us as sellers of the oil. Therefore, the oil producers are losing two to three dollars per barrel actually but the refinery is just losing the cost of paperwork done to take the monies out of our checks.

I wish to thank you for the opportunity to present this written testimony in behalf of myself and some of the independent oil producers in South Arkansas.

Mr. ANTHONY. Thank you very much.

Unfortunately, when you have a full day's worth of hearings and you have members that have other obligations, they can not all be here personally.

I was hopeful Mr. Rangel could be here. I think he was shocked to learn that Mr. Thomas said there was oil production in the State of New York. There are members of the full committee and the subcommittee that truly do not understand exactly how the business operates, and that is part of the purpose of this hearing, to make a record.

But, unfortunately, when you don't talk about it from a tax or energy policy standpoint, and you just talk about it from a political standpoint, and there is a need to increase revenues due to a huge Federal deficit, then, many people look at an area where they can see there are large dollars involved. And I, personally, felt that it would be instructive not only to Mr. Rangel, but also to others, to look at four young men that would like to make their futures in the oil business. Their future may be uncertain if the committee decided to take a different course of conduct as far as tax policy is concerned when it comes to these areas. I think your prepared texts, which have been submitted for the record and your summary statements, show that in our area especially, if these tax provisions are taken away, that it will have a very dramatic effect on your activities.

As a result, it is going to lower the amount of oil that is going to be produced, which in return will create a greater dependence on other regions of the country and/or imported oil.

I want to thank you for taking the time to come up here and assist me as a member of the subcommittee, and for presenting our case from our part of the country.

I do have one question I would like to ask Mr. Lowery.

If the exemption for stripper oil were amended or if it was covered on the day that the well was brought in, if it were below the 10 barrels, you didn't have to wait for 12, do you think that would have any inducement to encourage even more drilling in that particular area?

What would be your viewpoint?

Mr. **Lowery**. Yes, sir, that would also provide more immediate cash for the further well development, or for additional drilling of other wells, whereas we have to wait since that money is withheld.

So, it would provide even more incentive—if immediately on wells that start out as stripper, even though they are considered by definition newly discovered, if they were also exempt from the windfall profit tax at that point, that would provide us additional revenues on these marginal wells.

For some of the newly drilled wells we know perhaps for the first 12 months we would see very little profit, but we would continue to operate them because we know after the windfall tax is eliminated from those wells they will be profitable.

But there is one other thing I would like to point out.

I showed some of the staff of the Treasury Department the exhibit on the income and cost per barrel I presented in my written testimony that you mentioned earlier. It was pointed out to me by that staff member that this tax could be recaptured if the tax amounted to all of our profit on the well, and, of course, I did not point this out in my written testimony and it should be stated for the record, because I am sure it will come to the committee's attention. We can recapture, but keep in mind the windfall profit tax is taken out immediately. We do not ever receive the windfall profit tax that is withheld by the first purchasor.

The first purchaser that we sell our crude to takes the windfall profits out, and we never get to handle it.

We are able to recapture it later. For instance, right now we are just recapturing some of the windfall profit tax on marginal wells for 1980. We cannot continue to produce these wells that are losing money for 3 years to wait for this revenue and recapture it. So, that is my emphasis on the deficit shown in exhibit D.

Mr. **Anthony**. Thank you.

Mr. DeLone.

Mr. **DeLone**. One other point I would like to make that I think would be beneficial to the small independent.

That is the transfer clause in the windfall profit tax states that once—I believe this is correct—once the highest amount of tax—in other words, if a particular property is owned by an integrated oil company, a major oil company, and the highest tax is being taken out of that oil, when that is transferred to an independent, let's say, say I bought something from Texaco or something of this nature, it had gotten down to a point where they no longer particularly cared to operate it, it was not economical for them, and then this highest tax would always be carried on this no matter who owned it.

I think this is one thing that needs to be looked at because of the fact that so many of the wells that are operating in south Arkansas, or at least a large majority of them, have been drilled by large corporations or major oil companies, and have sooner or later filtered down to the independents. They may only be producing 2 barrels a day or 3 barrels a day, but this tax, and we do have some in this category, the tax is always on it at the highest level.

So, I think this is one thing that ought to be considered by Congress too, or looked at, that would be detrimental—or maybe I should say cause premature abandonment of some wells because of this higher tax bracket.

Mr. **Anthony**. I thank you for bringing that to our attention.

Mr. Pickle?

Mr. **Pickle**. Mr. Chairman, I am just thinking here. If I was to come into the room right now and hear these fellows' testimony, I would have to ask who they are. You don't look like oil operators to me. You look like fellows from Arkansas.

I would say the average age is 30, 35. I just wish the whole committee could be here to see these big oil people testifying they want to stay in the energy business. You have every right to make a go of it, the same as the larger fellows. I don't think a member of this committee would want to take away either IDC or depletion from these fellows.

Somehow, when this subject is brought up, everyone always thinks we are talking about the big independents and the majors. They say somebody is making an awful lot of money and we cut them back.

I have noticed from the testimony one of you had in 1981 three rigs running, but in 1982 you only had two rigs. Another fellow testified that he worked with a company that did have 140 people, 110 now, and going down.

The recession affects you like it does all the rest.

I think it is good you testified and got a lot of this out, and we can make it known to the other members of the committee.

I think a lot of people in east and west Texas are just like you are. I wish I could get them up from Texas and have them testify.

You have impressed me. I think when Mr. Rangel gets the testimony he will be impressed by your statements too.

The Chairman pointed out that we need to make a record on the different tax treatment among oil producers.

I hope today we have put out information that shows there is a difference, and there is a reason for it. Your testimony today makes me feel like this has been a good hearing. I am glad you invited your fellow townsmen.

Thank you.

Mr. **Anthony**. Thank you very much, Mr. Pickle.

Again, my thanks, not only personally for coming up, so that we can put on the record the facts for the producers in Arkansas, but also our thanks to the full subcommittee for participating in our oversight hearings so that not only the full committee but the Congress itself will have a better understanding of the necessity for the preferential treatment and the differences of the various tax breaks that have been put into the code, be it piecemeal or at any one time. And I think you have contributed much to our opportunity to present this case to the Congress.

We will be in recess until 10 o'clock tomorrow, same place, and we will hear further from additional witnesses on the same topic.

[Whereupon, at 5:50 p.m., the hearing was adjourned, to reconvene at 10 a.m., Friday, May 6, 1983.]

# TAX TREATMENT OF PRODUCERS OF OIL AND GAS

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FRIDAY, MAY 6, 1983

House of Representatives,
Committee on Ways and Means,
Subcommittee on Oversight,
*Washington, D.C.*

The subcommittee met at 10 a.m., pursuant to notice, in room 1100, Longworth House Office Building, Hon. J. J. Pickle presiding.

Mr. **Pickle**. The Chair will ask the subcommittee to come to order.

Today the Subcommittee on Oversight continues its hearings concerning the tax treatment of producers of oil and gas. The subcommittee is examining those provisions of the Internal Revenue Code which make distinctions between various producers.

As pointed out by Chairman Rangel at the beginning of the hearings yesterday, our objective is to receive information which will assist the subcommittee in analyzing the cumulative effects of the differences in tax treatment, how they are working, their cost in terms of lost revenue, and their benefits in terms of increased oil and gas production.

We have a large number of witnesses today. We are going to move along as quickly as we can.

I want to thank all our guests and participants for coming. We will try to receive your testimony and participate in questions and answers as quickly as we can.

Today we are going to reinstitute the procedure of the 5-minute rule, so that we can receive all the testimony. At the end of 5 minutes, the red light will appear. This doesn't apply to our first witness, but I am saying this for the record so the members and witnesses will be aware of it.

Our first witness this morning is the distinguished Senator from Oklahoma, the Honorable Don Nickles. He was not able to be with us yesterday when the Oklahoma delegation was here. We are pleased he could be with us this morning. We would recognize you now, Senator, to say whatever comments you wish.

## STATEMENT OF HON. DON NICKLES, A U.S. SENATOR FROM THE STATE OF OKLAHOMA

Senator **Nickles**. Thank you very much, Mr. Chairman.

I do ask your permission and consent to have my statement entered into the record. I won't read it.

Mr. **Pickle**. That will be fine. Your statement will be included.

Senator **Nickles**. Mr. Chairman, I regret that I was not able to join the entire Oklahoma delegation yesterday. I would have but we were in the process of marking up the natural gas decontrol bill. As you know, it is very important to our State as well.

In observing how long it is taking to mark up the natural gas deregulation bill I further realize how we came into some problems with the Natural Gas Policy Act and maybe the windfall profit tax. It is a slow and difficult task to consider such legislation.

Mr. Chairman, first let me say that I think that this committee's hearings concern me because many people have approached it from the angle that possibly there are certain additional taxes that should be levied on the oil and gas industry, particularly the oil industry.

I would like to say from the outset that there is no other industry in the United States that pays more tax than the oil industry. There is no other industry that has a windfall profit tax levied in addition to excise, gross production, and income taxes. The windfall profit tax is a very unfair, a very punitive, and a very negative tax which is certainly not in my opinion good tax policy, nor good energy policy.

I think it has been very detrimental, not only to the energy industry, but to the entire economy as a whole. We are not talking about a small tax, but we are talking about an enormous tax. Any suggestions about putting an additional or punitive tax should be discarded.

In 1981, the windfall profit tax brought into the Federal Government $23.2 billion. This compares, Mr. Chairman, to the total amount of Federal corporate tax of $64.6 billion. In 1982, the windfall profit tax brought in $18.9 billion, compared to a corporate tax of $49.2 billion.

Incidentally, on the corporate tax figures, a good portion of that also came from the oil industry. Therefore, if you couple the amount of corporate tax that the oil industry as a whole is paying with the very negative and punitive windfall profit tax, you will see that this industry pays more tax than any other industry in the United States. To talk about any additional tax would be ludicrous, and hopefully we will be able to stop those efforts should they be made.

If there is a change that really needs to be made in the area of energy legislation or taxation, it should be for a more equitable windfall profit tax, the reason being is that the windfall profit tax is only levied on domestic production.

Now, the net effect is that it discourages domestic production and encourages imports. It actually gives imports a competitive advantage over domestic production. We are penalizing our domestic producers who are paying taxes, who are employing Americans, who are helping revitalize our country, and we are encouraging the outflow of dollars. I think this is a very ridiculous energy policy, and that is our present policy.

If there really is a change that should be made, I would hope it would be for a more equitable treatment of the windfall profit tax between domestic and imports and not give this ridiculous advantage that we now have of importing oil without having this tax.

I am glad that some of the statements that have been made are bringing out the fact that the oil and gas industry in the State of Oklahoma, as well as the Nation, has declined and is in serious trouble.

Mr. Chairman, in February 1982 in the State of Oklahoma, we had 867 drilling rigs in operation. This month, in May 1983, we have 268. That is approximately a 70-percent decline.

I can tell you that if there are additional or punitive taxes, whether they are with respect to intangible drilling costs or percentage depletion, you will see that the percentages decline even further. It will penalize the oil industry today, but the net result will be that it will penalize all of America tomorrow. It would be very damaging and detrimental to both the country and the economy as a whole.

I would hope that this committee and Congress would show a little more common sense and appraise the tax problems and dilemmas we face with the shortfall of revenues and the excess of expenditures with an attitude of fairness and equity.

I think if we would do that, we would see that singling out the oil industry for additional taxes would be a wrong move, would be detrimental, and would be a mistake.

Mr. Chairman, I appreciate the opportunity to have a chance to share with you my thoughts. I appreciate, too, the fact that you let me just summarize those and enter my statement into the record.

[The prepared statement follows:]

### STATEMENT OF HON. DON NICKLES, A U.S. SENATOR FROM THE STATE OF OKLAHOMA

Mr. CHAIRMAN. Thank you for giving me the opportunity to testify before this committee on an issue of paramount importance not only to my state but to energy consumers across the United States. I was unable to join my distinguished colleagues from Oklahoma yesterday before this committee because of my involvement with the mark-up of the natural gas deregulation bill in the Senate Energy Committee.

Let me first say that even the mention of Congress tampering with the oil and gas industry has a terribly negative impact on an already depressed sector of our economy. Perhaps this is the result of the less than equitable way in which Congress has dealt with the industry in the past.

No other single industry pays more taxes to state and federal governments than the oil industry. The windfall profits tax took $23.2 billion in 1981, $18.9 billion last year, and will probably take about $14.3 billion this year. To put this into perspective, when taken as a percentage of corporate income tax, total windfall profits tax collections represented 38 percent of all corporate taxes paid in 1981 and then again in 1982. Putting politics aside and looking at the facts, the oil industry is definitely holding the short end of the stick when it comes to tax equity.

How can we begin to discuss fair and equitable tax treatment of the energy industry when it is obvious the industry has never been treated fairly by Congress? Why is it that no other natural resource has been the target of such biased tax policy? Why does no other industry pay a windfall profits tax?

On top of this inequity is the fact that the windfall profits tax presently affects only domestic production and not imported oil. This policy in effect, greatly penalizes domestic production while encouraging imports.

Those who have previously testified have sufficiently described the state of the domestic oil and gas industry * * * Drilling rig count down 69 percent from its peak in December 1981 (in Oklahoma as of May 2, the rig count was 268—down drastically from the 867 in February of last year), oil industry employment down 21 percent from last year, and on and on.

Apart from the fairness question is the issue of America's energy independence. We have seen government intervention into the taxation and regulation of oil and gas significantly affect our energy supply. In 1969, when oil and gas depletion was reduced we experienced the two largest historical drops in exploratory drilling in

1970 and 1971. It was only a few years later when OPEC nearly brought this nation to its knees with a crippling oil embargo. In 1976, when Congress imposed a tax preference on Intangible Drilling Costs (IDC's), exploration and development expenditures by independents increased only six percent that year. That compares to a 71 percent increase in the year before Congress acted to limit IDCs. If I didn't know better, it would sometimes seem as though Congress was working for OPEC rather than for the American people!

Because of the punitive tax and regulatory policies of the late 60's and early 70's, we did not have a domestic energy industry to rescue us from the iron grip of OPEC. With the advantage of hindsight, let us work together in developing policies which encourage production and exploration.

Mr. PICKLE. We thank you for coming, and we thank you for your statement.

I want to repeat to you and to our audience that the purpose of this hearing is not to consider proposals of either taking away or adding to any of the tax treatments we have in the oil and gas industry. We are trying to ascertain by overview, if the present policy we are following is a good one or if there should be changes.

I agree with you that the windfall profit tax is a negative tax against one industry, and it is the only one of that kind of tax in the history of the country. Naturally, those of us from the oil and gas-producing States object to that singling out. We hope that conditions will change and that eventually this will be proven to be an unfair tax.

Meanwhile, we are looking at our oil and gas production. My question to you, sir, is inasmuch as we give different tax treatment to the independents as distinguished between the majors or the integrated companies, is it your feeling that the difference in these tax treatments, or the preferential treatment for independents, is necessary, and would it increase domestic production if our present law is continued?

Should that distinction be made between the majors and the independents?

Senator NICKLES. I am not sure, Mr. Chairman, if I was crafting the legislation I would have made the initial distinctions that we see today. But I see some differences, just to give you an example, where we have depletion for independents and we don't for the majors. The distinction to me seems as if we should have depletion for all minerals. We have depletion at a rate of 22 percent on coal yet we have depletion on oil and gas for independents of 16 percent, phasing to 15 percent. So there is an inequity.

But the inequity would not be corrected simply by eliminating the depletion for independents. It would be to treat oil like all other minerals. We give percentage depletion on almost all minerals. On coal, which competes with oil, there is 22 percent, regardless if you are big or small. So it seems logical to me that the correct energy policy—not to differentiate so much between different minerals—would be to allow the percentage depletion on all of them, not to just single out one or the other.

Now, as the present statutes stand there is an advantage for the independents as compared to the majors. But again, I would hope that we would not go the one way and eliminate percentage depletion for the independents. I think we would have greater wisdom if we treat all minerals the same and give them all a comparable percentage depletion.

Mr. **Pickle**. I thank you, Senator.

Let me ask the other committee members if there are questions.

Mr. **Anthony**. Mr. Chairman, I want to welcome Senator Nickles.

In the area of depletion are you recommending that all minerals be treated equally? We had some witnesses yesterday who also testified that maybe all oil companies ought to be treated the same. They also talked about some of the consequences that can be derived as a result of that.

I take it from your other comments you would not be supportive of equalizing all of the tax provisions throughout the code for integrated companies and independent oil people.

Senator **Nickles**. It would depend on which way we equalize. I would not have a problem if you give a percentage depletion comparable to what the independents now have to the majors. But I would urge strongly and do what I could to see that we did not take it the other way. It depends how you equalized.

As I mentioned, there are some disparities in the treatment that we give, not only in depletion, but also in the amounts or degree of windfall profit tax liability, et cetera.

I would like to treat everything equally in windfall profit tax, and that would be to eliminate the windfall profit tax, and that would be equal, and that would be fair.

But I would not want to take and escalate the tax of independents up to the tax rates of majors, because the net result would be that you would be damaging the independent oil industry, and that would be very counterproductive to energy security and to the development of energy production in this country.

Mr. **Anthony**. What do you think would happen if you leveled it, but brought it back in the other direction, so independents were treated the same as integrated oil companies?

Senator **Nickles**. In other words, if you gave integrated oil companies the same percentage depletion as independents? I would advocate that. I don't believe that would be negative in any way.

Here again, compare coal. Regardless, if you are a big coal producer or small, you receive 22 percent depletion in coal production. I don't know why oil has been singled out for the majors, except that Congress was probably trying to get at the majors, the big boys, the Seven Sisters or whatever, so they eliminated depletion on the big oil companies. That was an inequity.

I think we have taxed this oil industry until the well is about dry. I don't know if we can continue to afford to try to balance the budget on the back of a single industry. I think it is counterproductive and shortsighted.

Mr. **Anthony**. Let me clarify this.

If in levelizing the Tax Code between integrated companies and independents, if it appeared as an economic consequence thereof, that a level rate was going to be more costly and more difficult on the independents, I take it your position would be different?

Senator **Nickles**. Not necessarily; here again it depends where you equalize. We used to have percentage depletion in oil similar to coal, about 22 percent. If we equalized that 22 percent for both independents and majors, I would certainly have no qualms about it. I think that would be good policy, and we wouldn't have the Government trying to direct or favor one segment of the industry over another.

Mr. ANTHONY. Thank you, Mr. Chairman.

Mr. PICKLE. Mr. Dorgan.

Mr. DORGAN. Thank you, Mr. Chairman.

Sorry I missed part of your testimony. Just a couple of comments.

One, you suggested there be no windfall profit tax. Just a question on that.

First of all, the price of oil went from $3 to about $38 a barrel pretty quickly, having very little to do with the free market. It had to do with pricing decisions by the OPEC countries.

If you did not have a windfall profit tax, would you not still have had a windfall profit?

Senator NICKLES. You would see a rapid rise in revenues, but also a rapid response that I think would have broken OPEC in a much shorter period of time. What we did by directly maintaining price controls in the seventies, and then indirectly maintaining price controls with the windfall profit tax, we continued to encourage the domination or control by OPEC. To carry that just a little further, if we and hold down those prices or put a very punitive tax on domestic production, you are giving OPEC an advantage.

The average windfall profit tax last year in domestic production was more than $6 per barrel produced in the lower 48 States. That is a burden that we are paying on domestically produced oil that they are not paying on imported oil. That gives them that much of an advantage.

If we eliminate that, we eliminate that advantage, or at least treat it equally. If you eliminate the windfall profit tax, and I submit to you a study that I asked CBO to do, stating if we eliminate the tax and place it on imports as well as domestic production, you would raise about the same amount of revenue, depending on the level of the tax.

[The CBO letter follows:]

CONGRESSIONAL BUDGET OFFICE,
U.S. CONGRESS,
*Washington, D.C., March 11, 1983.*

Hon. DON NICKLES,
*U.S. Senate,*
*Washington, D.C.*

DEAR SENATOR: This letter is in response to your request for an update of CBO's estimate of the level of oil excise tax needed to replace the windfall profit tax under different price assumptions. The attached table presents this calculation for fiscal years 1984–1988. Under the $29 oil price assumption, the "equivalent" tax is $1.66 per barrel in 1984 and declines steadily to $1.01 in 1988. The "equivalent" taxes under the $27 per barrel assumption are $1.41 and $0.76, respectively. These levels of tax would translate to 2 to 4 cents per gallon of petroleum product.

As seen in the attached table, gross fiscal year 1984 windfall profit collections are estimated to total $12.5 billion with a $29 per barrel world oil price and $10.5 billion under the $27 per barrel scenario. Under both cases, gross receipts decline throughout the 1984–1988 period. Because producers can deduct the windfall profit tax payments from their income for income tax purposes, we assumed that 54 percent of this figure represents net revenue to the government. In fiscal 1984, the net collections are estimated to total $6.9 and $5.9 billion for the $29 and $27 cases, respectively.

Unlike the windfall profit tax, an oil excise tax would raise U.S. oil prices. The increase in U.S. oil prices would, in turn, lower aggregate economic activity, which would lower federal revenues. In addition, the excise tax would be deductible as an added business expense. To raise the $6.9 billion or $5.9 billion in net revenues, the tax must be set at a higher level to accommodate these effects. We have estimated that under current conditions such a tax would have to be set at a level approximately 33 percent above the desired revenue target.

We have assumed that the oil excise tax would be imposed on all crude oil processed by domestic refiners and all product imports. We have also assumed that the approximately 1.1 million barrels per day currently exempted from windfall profit tax would also be exempted from the hypothetical excise tax. Baseline oil consumption was set at 15.8 million barrels per day in 1984, rising to 16.7 million barrels per day in 1988. The baseline consumption level was adjusted as different oil price assumptions were made. For the $29 per barrel scenario, average world oil prices were assumed to fall to $29 per barrel by mid-1983, hold steady for a year and then slowly rise to $33 per barrel by 1988. In the lower priced scenairo, oil prices are assumed to fall to $27 in mid-1983 and gradually rise to $31 per barrel by 1988.

Please do not hesitate to contact us if we can be of further assistance in this matter.

Sincerely,

Alice M. Rivlin, *Director.*

Attachment.

TABLE 1.—CALCULATION OF OIL EXCISE TAX LEVELS REQUIRED TO SUBSTITUTE FOR THE WINDFALL PROFIT TAX FISCAL YEARS 1984–88

| | 1984 | 1985 | 1986 | 1987 | 1988 |
|---|---|---|---|---|---|
| 1983 world oil prices of $29 per barrel: | | | | | |
| Estimated gross windfall profit tax (in billions of dollars) | 12.5 | 11.1 | 9.2 | 8.6 | 8.1 |
| Estimated "net" windfall profit tax (in billions of dollars) | 6.9 | 6.1 | 4.9 | 4.8 | 4.4 |
| Revenue required to replace windfall profit tax (in billions of dollars) | 9.2 | 8.1 | 6.5 | 6.4 | 5.9 |
| Resulting oil excise tax (in dollars per barrel) | 1.66 | 1.44 | 1.13 | 1.10 | 1.01 |
| 1983 world oil prices of $27 per barrel: | | | | | |
| Estimated gross windfall profit tax (in billions of dollars) | 10.5 | 8.9 | 7.0 | 6.6 | 6.3 |
| Estimated "net" windfall profit tax (in billions of dollars) | 5.9 | 4.9 | 3.7 | 3.7 | 3.4 |
| Revenue required to replace windfall profit tax (in billions of dollars) | 7.9 | 6.5 | 4.9 | 4.9 | 4.5 |
| Resulting oil excise tax (in dollars per barrel) | 1.41 | 1.14 | 0.84 | 0.83 | 0.76 |

I believe they anticipate that windfall profit tax collections for 1984 could be raised with about a $1.60 per barrel excise tax on both imported and domestic oil. So you could greatly eliminate this disparity that encourages or subsidizes those imports. And that is our current policy. It doesn't make sense from a tax policy perspective and doesn't make sense with regard to energy policy or production.

Mr. **Dorgan**. We did have some controls in this country imposed by President Nixon. We decided to eliminate the price controls and let oil in this country be priced at the world price, which was the price the OPEC countries were fixing. Clearly, that provided a windfall profit for the oil industry, because the cost of production has not jumped nearly to the extent the price was jumping in the years of the 1970's.

If we did not have a windfall profit tax, but clearly there was a windfall profit, you are suggesting the industry should simply keep the windfall profit because that would provide greater incentive for them.

Senator **Nickles**. Previously I stated that the windfall profit tax and the price controls allowed OPEC to have an effective cartel that could have been broken if we allowed the marketplace to compete. We didn't allow that.

Now, granted, there was a rapid rise in prices which was caused by world forces, the embargo, and the cartel. But that could have been responded to. If you are worried about the large revenue loss to the treasury, at least at that time, you would have seen approximately 50 percent of it channeled through the corporate income tax back to the government, the government would have received an equal windfall.

Even looking at that, we have had a lot of other windfalls. We saw the price of gold go from $35 to $800 in a period of about 8 years. Should we have a windfall on that type of escalation?

I bought a home worth about three times what it was some time ago. Should we place some kind of punitive tax on that? It escalated by forces outside of my control.

But when we intervene in that marketplace, what we have really done, instead of getting back at OPEC, or trying to control the amount of profit, we really subsidized and assisted them in their efforts in their cartel. If we had taken a different response and not had the punitive taxes and allowed the free world marketplace to operate, I think the cartel would have dissolved some time ago, not just in the immediate past.

Mr. DORGAN. Well, the point is there wasn't a free world marketplace. The OPEC countries were creating the market, controlling the market through the control of production. The question facing us earlier was when you have these kinds of windfall profits—there were substantial windfall profits—do you tax some of those profits, or do you provide them as incentive to encourage the companies? Those were the policy questions facing Congress.

You suggested the windfall profit tax should not have been imposed at all. I respectfully submit there are two different points of view. One is that when any industry incurs a substantial windfall profit, and we are talking about the magnitude of windfall profits here in the 1970's, because the price of oil went from $3 to $38 it was very substantial. The profits were substantial, and the question is, should the companies get it or should the people share in some of that through the windfall profit tax.

I was not in Congress at that time when the tax was enacted. I certainly would have been interested in some plowback provisions, because my interest was in seeing that we get as much domestic production as possible. The plowback would make sure those profits were sunk back into this country.

If I could ask one other question.

Congressman Pease and I had a study done by the Joint Tax Committee last year, and they took a look at the 1981 taxes of oil producers like Occidental Petroleum and others. The Federal income tax on domestic income for these big oil companies was about 3.1 percent. Occidental's was apparently zero.

The question is whether the oil industry is overtaxed. That could be true for segments of the industry. But on a general basis there are studies that show that for the industry as a whole the percentage of effective income tax is about 18 percent.

If you have a major company earning substantial money and paying no Federal income taxes or if you have an industry that pays an income tax rate of 18 percent which, incidentally, is lower than the tax generally, speaking of the lowest-paid person in the smallest town in your district—14 percent income tax, 7 percent social security tax, that is 21 percent effective tax on their income—can one very legitimately allege that the oil industry is undertaxed?

Senator NICKLES. You mentioned several different companies were surveyed and I am aware of two or three of those companies. At least one of those companies, Occidental Petroleum, avoided much of their tax liability through safe harbor leasing, which I object to in the first place. I think that was a mistake.

We have somewhat remedied that mistake, not totally. I would hope that we would go further and eliminate it, I think it should be phased out by 1983. I would hope we remedy that. A lot of companies drove a truck through it, and took advantage of it. But I think if you look at the oil industry as a whole, you would find it pays a fair share of the income tax.

According to a study performed by the American Petroleum Institute, using 1981 figures, the oil industry paid a greater proportion of net income in Federal income tax than nonoil companies.

The API compared the tax burden of 23 leading U.S. companies with a group of 100 leading nonoil companies. The study found that the U.S. current Federal income tax alone—not including windfall profit tax—as a percent of before-tax U.S. net income, was 20.9 percent for the group of oil companies in 1981 and 20.6 percent for the group of nonoil companies.

Again, if you consider the windfall profit tax along with the total amount of corporate income tax which last year totaled $49 billion, you find it is sizable in comparison. The total amount of windfall profit tax for 1982 was $18.9 billion and the corporate income tax was almost $50 billion. When taken as a percent of total corporate income tax collections you realize that you have one industry that is paying a tax—the windfall profit tax—of almost 40 percent of the total corporate income tax to which they are contributing as well.

Mr. DORGAN. Except you would have to stretch a long way to conclude that the windfall profit tax is an income tax.

Senator NICKLES. It is an excise tax.

Mr. DORGAN. There is a windfall profit. One should not add the windfall profits tax obligation to the income tax to determine the tax liability of the industry.

Senator NICKLES. It is a tax liability. Those are taxes going from that industry that are going to Washington, D.C.

Now, it may be on a different portion of their income statement, but it is taking some revenue from that company and transferring it to Washington, D.C.

You also have gross production taxes. I am telling you there is no other industry that pays more tax than the oil industry—period. If you add the windfall profit tax, you are looking at enormous sums.

I would just hope that you would keep that in mind when you are assessing the various changes or policy changes that you are reviewing with regard to this industry.

Mr. DORGAN. I understand your point.

The fact is the oil industry is simply handling the money of the windfall profit tax through an artificially inflated price relative to the cost. So we imposed a windfall profit tax. I think in many ways it has some characteristics to it that are unfair. But the reasons that the windfall profit tax was levied in the first instance, there were very good reasons. I don't think it ought to be considered as part of the income tax burden of the oil industry.

I appreciate your responses.

Mr. PICKLE. Senator, we thank you very much for your testimony. We appreciate your coming today. I am sorry you couldn't have been with us yesterday. We are glad to have your comments on the record.

Senator NICKLES. Thank you very much, Mr. Chairman.

Mr. PICKLE. Our next panel will be Mr. Robert McIntyre, and Mr. William Chandler. Mr. McIntyre is a director of Federal tax policy for the Citizens for Tax Justice.

The other gentleman is Mr. William Chandler, director, energy conservation project of the Environmental Policy Center.

Mr. McIntyre, will you proceed?

We are going to ask you to summarize your statement. Your entire statement will be made part of the record.

We have a very long list of witnesses today. I want to remind the members again, we are going to ask you to adhere to the 5-minute rule.

## STATEMENT OF ROBERT S. McINTYRE, DIRECTOR, FEDERAL TAX POLICY, CITIZENS FOR TAX JUSTICE

Mr. McINTYRE. Thank you, Mr. Pickle.

I guess all of us are pretty well aware that the Federal Government is now facing a terrible fiscal crisis, a crisis affecting the entire economy, because the Federal Government is borrowing so much of the savings available for private investment for purchase of cars, homes, and whatever.

There is also a crisis, I think, in respect for the Government among ordinary Americans. The past few years we have seen the polls indicate that people's respect for the Government is going down, and largely that is due to the fact, I think, that they perceive the Government as wasting their money.

We have a situation where the taxes of ordinary folks for the last 5 years have been going up, despite all kinds of so-called tax cuts, because of inflation and higher social security taxes. And they see the taxes going up, and they see themselves getting very little more from the Government. Their presumption is that the Government must be wasting their money. That presumption is not necessarily correct because what has really been going on is that the Government has not been collecting as much money as it used to because of all the special tax breaks that have been added for good and bad reasons, particularly over the last few years.

It seems to us that as we face the need to raise taxes this year and probably in the future that the direction we ought to be looking at is towards those industries or individuals who currently are not paying their fair share. It also seems very clear to us that one of those industries worth looking at is the oil industry, particularly the independent producers.

We have in our testimony a chart on page 5, of nine companies that we looked at, that we chose at random, publicly held independents, and of that group of nine companies, only three paid any taxes at all, and overall they received a net refund.

Congressman Dorgan's study with Representative Pease found a 3-percent rate on five larger independents.

We also found many of the companies we looked at have not been paying taxes for many years. So we are in a situation now where the income tax is not being assessed against these companies.

Now, typically, the independent oil producers argue they are entitled to these tax breaks for several reasons—because their business is risky, because they are good American entrepreneurs, and because they need to attract capital. The final line of that argument, the anticapitalism argument, is that a dollars' worth of oil is somehow worth more than a dollar. And in fact we have been paying in many cases much more than a dollar to drill a dollar's worth of oil.

The economist Arnold Harburger studied this issue a few years ago and found we were spending $2 for every dollar of oil we were getting. Recently, the Congressional Research Service did a study which found we still have negative tax rates on the independent oil production sector, which in essence means we are spending more than a dollar to get a dollar of oil.

Now, you don't have to be a free marketer to wonder why it makes sense to do that. That is usually called waste. And the kind of waste we are talking about is encouraging money to go into the oil industry when its rate of return is lower before tax than it would be somewhere else.

It is very easy to understand why United States Steel wanted to buy Marathon Oil rather than modernize its steel plants, but it is very hard to understand why the Federal Government should want to encourage them to do it.

In conclusion, let me say that it seems to me these hearings are going to send a message to somebody when they are over. Some people have suggested I think cynically that the message is for the independent producers, and something to do with campaign money. I don't believe that. But I do believe, whatever you do, it will send a message to the American people, and the message is this:

Whether they think this committee and the Congress will give fair treatment to all the people out there who don't have a political organization, or who do pay taxes on every penny of wages and salaries they do, and who, despite the fact they don't have percentage depletion, are the ones who provide the backbone of this country and the ones who are going to make this country prosper if in fact we get fair treatment.

Mr. PICKLE. Thank you.

[The prepared statement follows:]

## STATEMENT OF ROBERT S. MCINTYRE, DIRECTOR OF FEDERAL TAX POLICY, CITIZENS FOR TAX JUSTICE

> *"And what of the return reaped by the oilmen on an investment in Lyndon Johnson that, as years passed was to grow and grow? What did they want from government?*
>
> *"They wanted a lot: not only continuation of the oil depletion allowance and of other tax benefits, and of exemption from federal regulation but new benefits, and new exemptions–and other new, favorable government policies. . . . [T]hey wanted government favoritism on a scale so immense that it would become a significant factor in the overall political and economic development of the United States."*
>
> *Robert A. Caro,*
> The Years of Lyndon Johnson
> The Path to Power *(1982)*

Politics is central to the way oil income is taxed, and the taxation of oil long has been central to tax politics generally.

For many years, the power of oil money dominated the decisions of the Ways and Means and Senate Finance Committees. As John F. Manley notes in *The Politics of Finance: The House Committee on Ways and Means* (1970), it was well known in the Johnson-Rayburn years "that the party leaders would not let a Democrat on Ways and Means unless he was . . . against cutting the oil depletion allowance . . ." Similarly, Thomas J. Reese recalls in *The Politics of Taxation* (1980), "[d]uring the 1950s and 1960s, the oil depletion allowance was the major issue that determined whether or not a person was appointed to the Finance Committee."

Refusal to "take the pledge" on oil tax breaks kept Representative Charles Vanik of Ohio off the Ways and Means Committee until after Sam Rayburn died. Lyndon Johnson went to great lengths as Senate Majority Leader to deny a seat on the Finance Committee to Paul Douglas of Illinois, at one point even joining the Finance Committee himself to avoid a Douglas appointment. Senator Douglas finally did become a member of the Finance Committee, but Senator William Proxmire (D-Wisc.) was permanently blocked.

Even as oil's power on the tax-writing committees waned to a degree in the second half of the 1970s, the independent producers, the source of most oil political campaign funds, retained most of their advantages. When Congress repealed percentage depletion in 1975, the independent producers were exempted. When Congress enacted a windfall profit tax to accompany oil price decontrol in 1980, the independents' share of the burden was reduced to a pittance–and was cut even further in 1981. When Congress took a small nibble at the intangible drilling costs loophole in 1982, independents were again exempted.

How much does the oil industry spend on its investment in politics? Firm figures are hard to come by, but the answer is clearly a lot. Oil political action committees gave at least $8 million to federal candidates in the last election. Direct individual contributions from oil interests were almost certainly much larger. Writing in *The New Yorker* last December, Elizabeth Drew notes that "an oil lobbyist told me he estimated that only about a third of the independent-oil industry's contributions are made through PACs." According to the same lobbyist, adds Drew, "the idea that the law requiring the disclosure of funds contributed to congressional campaigns gives a real picture of the sources of the funds is 'a joke.' " In 1981 and the first half of 1982, the national party committees took in $2.3 million in individual contributions of $500 or more from the three major oil producing states, most of which can be directly linked to independent producers. "Soft money" in the last Presidential campaign is estimated to have included at least $7 million in oil money. The $40-million-plus budget of the American Petroleum Institute exceeds the combined salaries of all federal elected officials.

But even if the oil industry spends $150 million every two years on politics—even if it invests twice as much—the payback is well worth it. Two oil tax breaks alone—percentage depletion and the expensing of intangible drilling costs—are estimated to save the industry $6.3 billion in taxes over the next two years. The 1981 tax act was designed to be worth at least $90 billion to the oil industry over the decade of the 1980s (and even with the 1982 reforms, will be worth about half that much).

A look at the annual reports to stockholders of some of the publicly held independent producers provides fascinating, concrete insights into the benefits they have gained from their political investments. The nine randomly chosen companies in the accompanying chart, for example, earned a total of $476 million in 1982, but only three of them paid any federal income taxes at all. As a group, they received a net tax *refund* of $17.5 million. Of the nine, five paid no federal income taxes in 1981, and four of these paid nothing in 1980.

These companies are not likely to be paying taxes in the future either. Many of them note that they are carrying excess deductions and credits forward for use in later years. For example, Mesa Petroleum says it has $129 million in "loss" carryforwards and $29 million in investment tax credit carryforwards; Inexco has $164 million in excess deductions and $9 million in excess credits. Some of the companies took advantage of "tax leasing" last year to make use of the overflow of tax concessions. For example, Mesa sold tax breaks for $19 million in 1982; Lear Petroleum sold an unspecified amount. Last year's Treasury report on leasing found that, through the end of 1981, crude oil producers had sold tax breaks for $164 million (and this figure does not include another $138 million in sales by petroleum refiners).

Last December, at the request of Representatives Pease and Dorgan, the staff of the Joint Committee on Taxation took a look at the 1981 taxes of five large crude oil producers. The companies studied were Occidental Petroleum, MAPCO, Superior Oil, Natomas, and Louisiana Land & Exploration, which together earned $3.9 billion world-wide before-tax in 1981, and about $1 billion in the United States. Overall, the staff found a federal income tax rate on domestic income of 3.1 percent, including, apparently, Occidental's zero rate and Louisiana Land's 10 percent rate.

## 1982 FEDERAL INCOME TAXES (OR REFUNDS) FOR NINE RANDOMLY SELECTED INDEPENDENT OIL PRODUCERS

| Company | Pre-Tax Income (millions) | Federal Income Tax (millions) | Effective Tax Rate |
|---|---|---|---|
| *Mesa Petroleum Corp. | $195.5 | $ 0 | 0 % |
| Louisiana Land & Exploration Co. | 111.3 | (19.7) | −17.7% |
| Apache Corporation | 44.4 | 0.2 | 0.4% |
| *Adobe Oil & Gas Co. | 37.4 | 1.9 | 5.0% |
| *Inexco Oil Co. | 26.7 | 0 | 0 % |
| Felmont Oil Corp. | 22.7 | 3.0 | 13.3% |
| Dyco Petroleum Corp. | 21.7 | (2.9) | −13.2% |
| *Damson Oil Corp. | 10.0 | 0 | 0 % |
| *Lear Petroleum Corp. | 6.3 | 0 | 0 % |
| TOTALS | $476.0 | $ (17.5) | −3.7% |

*Zero federal tax in 1981.

NOTES: Pre-Tax Income refers to net income before federal income taxes (but after deducting any state or foreign taxes paid). Federal Income Tax refers to taxes actually paid, that is, "current" federal taxes (and does not include so-called "deferred" taxes, which are taxes not paid due to various shelters.

SOURCE: 1982 Annual Reports.

Currently, the federal government faces a fiscal crisis. Huge deficits as far as the eye can see threaten to keep long-term interest rates high and abort whatever recovery we experience this year. Much of the blame for those deficits rests on the special-interest politics that dominated tax writing in much of the 1970s and especially in 1981. Corporate "tax expenditures," which were only $7 billion in 1970, are estimated to total $56 billion this year, and $83 billion by 1986. In fiscal 1983, the federal government will provide $1.60 in corporate loopholes for every dollar it collects in corporate income taxes, up from 60 cents on the dollar in 1979 and only 20 cents on the dollar in 1970. At the same time that the business tax base has been eroded, "bracket creep" and rising social security taxes have pushed up taxes on average Americans, most of whom will continue to pay a higher share of their income in taxes than they did in 1980 despite the so-called "across-the-board" tax reductions of 1981.[1]

Many members of Congress are now searching for ways to increase federal revenues that make the tax system more rather than less fair. That is, they would like to raise money, while avoiding further increases in the tax burdens on middle- and lower-income Americans.

As the 1982 tax act proved, such a result can be achieved, but only by targetting tax hikes on those taxpayers who currently are failing to contribute adequately to the support of the government. These hearings, therefore, come at an auspicious time, since one industry that we know is not paying its fair share of income taxes is the independent oil producers.

The stated purpose of these hearings is to evaluate whether continued tax breaks for oil income make sense in the current environment (or indeed if they ever made any sense). In light of the pressing need to raise revenues and to improve tax fairness, the burden should be on the proponents of these tax loopholes to justify their retention.

What do defenders of oil loopholes offer to support the special tax concessions? Typically, they have three things to say: First, they argue that exploring for oil is a risky business. Second, they say that independent oil producers are fine examples of American entrepreneurship. And, third, they maintain that tax shelters are essential to attract sufficient capital to the oil business.

What these arguments boil down to is just one assertion: that the marketplace on its own provides insufficient return to encourage drilling for oil. Or, put another way, the bottom-line defense of oil tax breaks is apparently that a dollar's worth of oil is worth more than a dollar.

Economist Arnold Harberger once calculated that the various oil tax breaks made it profitable to spend $1.95 to drill $1 worth of oil. A 1968 Treasury study found that the depletion allowance at that time was costing average taxpayers more than $9 for every dollar in added oil reserves. A recent Congressional Research Service study (April 13, 1983) found that effective tax rates on independent oil producers are still "negative," that is, profits are higher after-tax than before-tax (a fact reflected in the chart above).

One need not be a hide-bound free-market capitalist to wonder why it makes sense to encourage spending more money to drill for oil than the oil is worth. Such activities are usually called "waste."

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[1] For a fuller examination of the tax-shift policies of the past several years, and how they have hurt both tax fairness and the economy, we recommend CTJ's new book, *INEQUITY & DECLINE*, just published by the Center on Budget and Policy Priorities.

What waste means in these circumstances is that the tax laws encourage the diversion of capital funds toward oil and away from other investments. It's easy to understand why U.S. Steel prefers to buy Marathon Oil rather than invest in modern steel plants, but it's not so easy to understand why the federal government wants to provide incentives for such activity.

A closer look at the two major oil-specific tax breaks–percentage depletion and the expensing of intangible drilling costs–raises further questions. For example, *without* expensing for IDCs, risky exploratory drilling would be encouraged, since dry holes would be entitled to an immediate write-off in any case. By extending the same treatment to successful wells, the tax laws discourage exploratory drilling in favor of punching new holes in old fields. Percentage depletion, which is only available for successful wells, has a similar impact.

Some have suggested that now might be a bad time to raise oil taxes, since falling oil prices have created difficulties for some producers. This is a false argument. Added income taxes will not affect those producers which have no income. What we are talking about is requiring those companies which are profitable to contribute a fair share of their income to help support the federal government. This does not seem too much to ask.

These hearings could help give the Ways and Means Committee and the Congress an opportunity to close or narrow oil tax loopholes that for years have proven to be both extremely expensive and economically counterproductive. Scaling back or phasing out percentage depletion, requiring intangible drilling costs to be amortized over the useful life of productive wells, extending the depreciation period for oil refineries to 10 years (instead of the current five years), tightening the rules on oil foreign tax credits further, and so on are the kind of steps we suggest. They could contribute to a 1983 tax bill that protects middle- and lower-income Americans from further increases in their tax burdens, while at the same time moving back toward federal fiscal responsibility.

For millions of Americans, such steps could help restore legitimacy to our tax laws by demonstrating that, regardless of the campaign contributions of the oil industry or any other special interest, this Congress will not defend unfair and economically destructive tax loopholes. As for the oil industry, numerous experts of all political persuasions have told this Committee over the years that tax breaks are not essential to the search for oil. Indeed, perhaps the industry might respond to these needed reforms by re-evaluating the risks of its political investments and looking instead to the marketplace to earn its profits.

There is a growing belief among taxpayers that our tax laws are fundamentally unfair. The 1981 tax act added fuel to that belief. Some cynics have even suggested that this hearing is intended by Democrats to send a message to oil producers that the recent shift in political contributions dramatically in favor of Republicans had better be reversed or serious retribution may be in order. We hope those cynics are wrong. But whatever the outcome of these hearings, the important message will be the one you send to average American taxpayers, who have no PACs to lobby for tax loopholes, who pay withholding taxes on every penny of the wages and salaries they earn, and who–without a 60 percent exclusion or accelerated cost recovery or percentage depletion– provide the strength, the energy, and the creativity our country depends upon to prosper.

Mr. PICKLE. Mr. Chandler, you may proceed.

## STATEMENT OF WILLIAM U. CHANDLER, DIRECTOR, ENERGY CONSERVATION PROJECT, ENVIRONMENTAL POLICY CENTER

Mr. CHANDLER. Thank you, Mr. Pickle.

I want to speak to the issue of the tax treatment of energy conservation relative to energy supply and especially oil and gas.

Energy conservation investments save energy for a fraction of the cost of new energy supply. Yet Federal tax subsidies for energy production outweigh those for conservation by 11 to 1, and this ratio will triple by 1986. The growing budget deficit crippled recent congressional efforts to increase incentives for energy conservation. The deficit, in fact, makes it extremely unlikely that fiscal incentives for conservation can be increased to parity with those for supply.

The Environmental Policy Center concludes, then, that both energy and fiscal policy would be served by cleaning the slate of tax subsidies for energy. We urge that Congress start with the largest and most counterproductive of these—subsidies for the production of oil and gas.

Eliminating subsidies to oil and gas producers would, in addition to improving energy policy, send U.S. taxpayers an important message. It would show that Congress gives priority to tax reform over increasing the taxes of ordinary citizens.

### THE VALUE OF ENERGY CONSERVATION

Energy efficiency measures taken since 1973 save the United States approximately $80 billion each year.[1] Home heating oil costs about $1.25 per gallon, but ceiling insulation can save oil at an average cost of 16 cents per gallon. Conservation possibilities range from clock thermostats that save oil for only 5 cents per gallon to storm windows that save oil for 80 cents per gallon.[2]

In industry, capital retrofits offer comparable savings. For example, retrofitting evaporators, commonly used in the paper, chemicals, and food processing industries, saves oil or gas at a cost of less than 15 cents per gallon. Similar investments abound in other industrial equipment and processes. Industrial cogeneration could provide 100,000 megawatts of electric power in the United States, generally at a cost below new central station facilities.

Five-passenger, 60-mile-per-gallon cars can now be built economically. Saving gasoline by producing 60-miles-per-gallon rather than 30-miles-per-gallon automobiles costs only about $1 per gallon saved.[3]

Overall energy conservation investment opportunities in the United States now exceed $300 billion. Unfortunately, this vast opportunity goes untapped, largely due to a shortage of capital. The tax code exacerbates this problem by allocating capital to energy production and, it follows, away from energy conservation. This diversion of capital not only reduces investment in conservation, but subsidizes the price of fuels and thus encourages energy consumption and waste.

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[1] Eric Hirst, *et al.*, "Recent Changes in U.S. Energy Consumption, What Happened and Why", Oak Ridge National Laboratory, February 1983.

[2] See, for example, p. 170 of *Energy: The Conservation Revolution*, John H. Gibbons and William U. Chandler, Plenum Press, New York, 1981.

[3] *Ibid*, pp. 219–220.

### CONSERVATION VERSUS SUPPLY

The Federal Tax Code strongly favors energy production over energy conservation. Tax subsidies for energy supply last year outweighed subsidies for energy conservation by almost 10 to 1. Not only does conservation fare badly now, but it will fare far worse in the future.

In 1984, energy supply will receive tax incentives almost 14 times as great as those for energy conservation. In 1985, supply will receive 20 times more in subsidies. Conservation tax subsidies will virtually disappear in the next 4 years, while supply subsidies will grow larger. In 1987, energy supply will receive $540 of subsidy for every dollar allotted to energy conservation. [See table 1-A.]

Behind these ratios lie huge sums of money. Energy supply incentives totaled $7 billion in 1982, compared to $0.72 billion for energy conservation. Supply incentives will grow to $10.77 billion by 1987, while conservation incentives will shrink to $0.37 billion in 1986, and to $0.02 billion in 1987. [See table 1-B.]

Moreover, oil and gas subsidies represent 78 percent of all direct energy-related tax subsidies. The share allotted to oil and gas is expected to grow to 84 percent by 1987. In contrast, conservation's share of incentives will shrink from 9 percent to .2 percent between now and 1987. [See table 1-C.]

[A table follows:]

TABLE 1.—DIRECT TAX INCENTIVES, CONSERVATION VS. SUPPLY

| Category | Year— | | | | | |
|---|---|---|---|---|---|---|
| | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 |
| 1-A: billion dollars per year: | | | | | | |
| Conservation | 0.74 | 0.70 | 0.59 | 0.46 | 0.37 | 0.02 |
| Supply | 7.0 | 7.4 | 8.1 | 9.4 | 10.4 | 10.8 |
| 1-B: Ratio, supply/conservation | 9.5 | 10.6 | 13.8 | 20.0 | 28.5 | 538.5 |
| 1-C: Conservation as a percent of supply | 11 | 9 | 7 | 5 | 4 | .2 |
| 1-D: Oil and gas as a percent of all direct energy subsidies | 78 | 77 | 76 | 76 | 77 | 84 |

Source: Environmental Policy Institute, derived from "Tax Expenditures: Budget Control Options and Five-Year Budget Projections For Fiscal Years 1983–1987", U.S. Congressional Budget Office, November, 1982, p. 53.

Mr. CHANDLER. It is anachronistic to encourage energy consumption and waste and to fail to provide incentives for conservation. Our present energy-related tax policy is bad energy policy.

### THE NATURE OF INCENTIVES

Some may object that it is unnecessary to provide incentives to companies or individuals to invest in any measure as attractive as energy conservation, and that subsidies should be reserved for high-risk but high payoff investments. This sentiment, in our opinion, represents a misunderstanding of the nature of the incentives, and of the character of energy conservation investments.

The purpose of tax incentives should not be, as some would argue, to increase the attractiveness of certain investments by using subsidies to increase their rate of return. The tax code is not a powerful tool for increasing rates of return; subsidies cannot usually be made large enough to effect large increases in rates of return. Neither is the tax code an especially efficient stimulus for investment: Typically, about 65 cents of investment is made for every dollar of incentive.[4] The budget deficit, moreover, suggests that the United States cannot afford to provide sufficient levels of incentives to stimulate hundreds of billions of dollars of investments.

The tax code does serve to increase cash flow for investors at critical points in an investment, especially in the first years, and therefore make investments more feasible. Sizable tax incentives, such as the expensing of intangible drilling costs, also reduce risk sufficiently to encourage investors to take larger chances.

Oil and gas investments are without question risky. But so are conservation investments. Though conservation systems generally are technologically well developed, consumers often lack familiarity with them and therefore perceive them as risky. Tax incentives for conservation investments provide some insurance for risk-averse investors in the same way as do oil and gas tax incentives. Conservation incentives thus have merit.

The central question, however, is this: How much can the Nation afford to spend stimulating energy conservation?

The previous Congress gave one answer: It failed to extend industrial energy conservation tax credits, including one for industrial cogeneration; these expired at the end of 1982. Realistically, the budget deficit precludes us from increasing energy conservation tax expenditures to equal those for supply.

The Federal budget deficit and the need to reform U.S. energy policy combine to argue strongly for repeal of energy subsidies, especially those for oil and gas production. Repeal of percentage depletion and expensing of intangible drilling costs would accomplish much of the needed reform since these two items represent more than three fourths of all direct energy tax subsidies. Repeal of these measures would save a total of approximately $30 billion over the next 4 years.

## CONCLUSION AND POLITICAL RAMIFICATIONS

American voters have become increasingly aware of the need for tax reform. Before taxpayers are asked to sacrifice the third year of the Reagan tax cut, which will benefit middle-income taxpayers more than upper-income levels for the first time, or before Congress repeals indexing, it must take serious action to repeal unfair and conterproductive measures such as oil and gas percentage depletion and intangible drilling costs. Removing massive tax subsidies for producers of oil and gas makes sense for fiscal as well as energy policy.

Thank you.

Mr. PICKLE. Thank you, Mr. Chandler.

Any questions?

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[4] See, "Industrial Energy Conservation: Potential and Costs", Holly L. Gwin, Environmental Policy Institute, May 1981.

Mr. ANTHONY. Thank you, Mr. Chairman.

I would like to ask Mr. McIntyre two or three questions.

On page 2 of your testimony, you talk about some of the larger companies, the amount of loss carryover they have, and the amount of investment tax credits they have carried forward. You have a 10-percent investment tax credit. If you have a $29 million investment tax credit, that means that there was an awful lot of investment that was put into the industry in order to earn that 10-percent investment tax credit, was there not?

Mr. MCINTYRE. Yes.

Mr. ANTHONY. What disturbs me is that you only paint one side of the picture in that particular case. You show the carry forward, which is something that is not only for the oil industry, but appears throughout the business community.

Are you saying we should eliminate the investment tax credit?

Mr. MCINTYRE. I am not sure it is the subject of this hearing, but if you ask my advice, I would say yes.

Mr. ANTHONY. To some extent it is the subject of this hearing that is, whether or not any of these various subsidies or tax provisions should be included as part of our tax policy. It is something that runs through the entire code. I just wondered if you thought it should be eliminated totally.

What really piqued my interest, and this is totally off the subject of the code itself, are the comments on page 4 of your testimony. You have stated that much of the blame for the deficits we are experiencing today rests on special interest, politics-dominated, tax writing. You find this especially true in 1981.

What I find so unusual about this is that special interest groups had to lobby a Republican President, a Republican-dominated Senate Finance Committee, and a Democratic-dominated Ways and Means Committee.

Mr. MCINTYRE. That is true.

Mr. ANTHONY. And you are stating that all of the deficits, or at least the largest percentage, were created after 1981.

Mr. MCINTYRE. I don't think there is any question about that, Mr. Anthony, that much of our problem has to do with the fact that we have wiped out most of the corporate income tax, that we have enacted new tax breaks that cost tens of millions of dollars a year, many of them in 1981, some of them in previous years. As a result, we are not collecting enough money to fund the Government.

It is my understanding from studies that have been done that the effective tax rate on the average individual, after you take into consideration all of the credits and deductions that are allowed under the code for individuals versus the oil people, that the effective tax rate is about 15.5 percent.

That is about right.

Mr. ANTHONY. That is below the Pease-Dorgan study printed in the Congressional Record.

Mr. MCINTYRE. Crude oil producers came in at 3.1 percent. So that is below the average taxpayer.

Mr. ANTHONY. I am just going by what Mr. Dorgan said a few minutes ago. He said about 18.3 percent on domestic.

Mr. McIntyre. Not on producers. If you include the revenues you get a higher rate.

We picked literally at random nine independent producers. Of those we could only find three paying anything at all, and net refunds.

Mr. Anthony. The only point I am trying to make is you favor repeal of all tax credits and exemptions for the oil and gas industry. You believe this is bad tax and energy policy. This appears to me to be a wholesale assault on the entire Internal Revenue Code. If we were going to repeal those provisions, perhaps we should review some of the flat tax proposals. Conceivably, some of these proposals could bring fairness, equity, and some understanding to the tax code. So to that extent I may agree with you—as long as you don't start by picking on one industry. You would probably get strong support here if you advocated a complete overhaul of the code.

Mr. Pickle. Thank you very much.

Mr. Dorgan.

Mr. Dorgan. Thank you, Mr. Chairman.

Thank you for the statements you have given the committee.

Let me first indicate my agreement with your statement about the 1981 Tax Act. I was also pleased to hear Mr. Anthony say that he agreed that we might want to look at what we did back in 1981 and restore some revenues on the areas where tax expenditures were developed that were terribly inefficient, accomplished nothing except giveaways to industries that didn't need the money.

I personally think that we ought to change the tax code with respect to corporate tax in a very dramatic way .

I would support the full integration of the corporate income tax, eliminate whatever double taxation exists at the corporate level, on stock dividends—to the extent that double taxation exists; I would support eliminating that through integration and having a single corporate income tax and encourage the companies to force some of that money out of the corporations.

With respect to the independent oil producer, I do want to ask you a couple of questions.

The independent producer, according to data that I have seen, reinvests a larger portion of his earnings and his capital than do the integrated companies. If that is true, if empirical evidence exists that the independents are reinvesting more than the integrated companies, is there not then reason to have preferences in the tax code to continue to encourage that on behalf of the independents?

Mr. McIntyre. If you believe in capitalism, your answer would be no. It is true because of the enormous tax breaks available to independent producers, there is a very heavy incentive to reinvest heavily in oil production, an incentive which goes way beyond what anyone would call rational. We are diverting capital into an industry long past the point where that capital is going to give us a return.

That usually looks like waste. It doesn't look like waste to an independent producer, because the bottom line is fine after tax, but to the society as a whole it is not a paying proposition to encourage that.

Mr. Dorgan. It seems to me the independent is in a substantially different position than the majors. The major has purchased department stores and whatever else happened to provide incentives from our own tax code to go out and acquire, and have the public pay part of the cost.

The independents are in a substantially different position, because the independent may very well make it quickly, and lose it quickly. And when they lose it, they are done.

The majors generally have an economic base that allows them to withstand some down period in these periods of peaks and valleys. But I have a friend who is an independent oil producer who made a tremendous amount of money in a very short time and lost it even more quickly, and it is still gone.

My point is——

Mr. **McIntyre**. Now I think he is entitled to a subsidy.

Mr. **Dorgan**. My point is that in many respects he typifies the kind of independents I am interested in and concerned about, the person who is an enormous risk-taker, really in the larger sense of the word, who has, in this person's period in the oil industry, in a short period made and lost it all. It is characteristic I think that the smaller independents, that they incur that kind of risk, and much of the risk I expect is because they keep putting that back in.

If they have a streak of a couple of dry holes, it is all gone. And I think there is a substantial difference between the independents and the integrated companies, in the way they operate, the financial risks they take, the rewards they receive. And I think that what we are trying to do in these hearings is determine whether there exists in the tax law any significant reason to have different tax provisions for independents versus majors.

If I might just make a more general comment about your statement about the tax system. I am in general agreement with what you are saying about our tax system. Our tax system is a punchboard of gimmicks and loopholes and often turns good investments into bad investments or bad investments into good investments. I think it really desperately needs an overhaul.

I think what we did in the 1981 law allows, as we found out recently, someone to writeoff the cost of a battleship or a ship that is leased to the Navy, write it off in 5 years for depreciation purposes. Thus, I think the point you make is very valid. We really ought to take a look at this whole code and figure out what we are doing in it.

I appreciate the statements of both of you.

Mr. **Pickle**. I thank you, Mr. Dorgan.

I might add we hope to have a bill introduced on this leasing issue, and would welcome you as a cosponsor. I am glad to know of your interest in it.

I thank both of you gentlemen.

Mr. McIntyre said in effect he was basically concerned that certain oil companies were not paying enough taxes, or paid very little taxes, and that that was unfair.

Mr. Chandler says we are spending more for production than conservation. And you both may have good points. But that is not the purpose of these hearings. We are trying to concentrate on the differences in tax treatment between oil and gas producers. And I have to assume basically you, Mr. McIntyre, would be against depletion, and if you are against depletion—you nod affirmatively—I assume you would be against depletion for the other industries that get depletion.

You make your point legitimately. I think it is worth while to hear what you have to say.

Your testimony makes us stop and think if we are doing the right thing. So we appreciate your testimony. We thank you for coming.

Our next witness is Mr. John Lichtblau, president, Petroleum Industry Research Foundation, Inc., New York, N.Y.

We are glad to have you. If you will have a seat, we ask you to proceed.

We would ask you to summarize your statement and then we will ask you questions.

## STATEMENT OF JOHN H. LICHTBLAU, PRESIDENT, PETROLEUM INDUSTRY RESEARCH FOUNDATION, INC., NEW YORK, N.Y., ACCOMPANIED BY CHERYL TRENCH, RESEARCH DIRECTOR

Mr. **Lichtblau**. Thank you, Mr. Chairman.

I have with me Cheryl Trench, our research director who has done a lot of the work in this study we are presenting here in case questions come up.

Thank you for inviting me to testify before the Subcommittee on Oversight's hearings on the tax treatment of oil and gas producers. As you know, my testimony will not deal directly with the subject of taxes, but it is intended to provide some background information through analysis of the domestic oil and gas exploration activities of the large integrated oil companies, the so-called majors. To the extent possible we will compare their activities with those of the U.S. oil- and gas-producing industry as a whole.

The reason for our analysis is that in energy policy debates involving regulation or taxation of the petroleum-producing industry, there is often a distinction drawn between the majors and the independents. The latter operate entirely or primarily in the producing segment and are usually substantially smaller than the integrated majors.

It should be noted that the distinction between a major and an independent is not clear-cut. Different criteria have been appplied for differing policies and regulations. The Department of Energy's now defunct crude oil allocation program defined 15 companies as majors based on their level of integration and refinery capacity. By contrast, the Internal Revenue Service regulations implementing the Crude Oil Windfall Profit Tax Act have the effect of classifying companies with any downstream integration as nonindependents, thus subjecting their oil production to higher tax rates. Similarly, the depletion allowance is available only to producing companies with no forward integration.

The group of major companies for which we have assembled the pertinent information for 1980 through 1982 consists of 23 companies whose collective net petroleum and natural gas reserves, on a BTU equivalent basis, accounted for 57 percent of total U.S. reserves at the beginning of 1982 and whose net production last year accounted for about half of total U.S. oil and gas production.

Gross production of these companies is about 16 to 17 percent larger than their reported net figures, since it includes the shares of the royalty owners on whose land or offshore shelf the reserves are located. Thus, operationally these 23 companies accounted for about 62 percent of U.S. production last year and held two-thirds of U.S. reserves.

The balance of U.S. oil and gas reserves is held and produced by independent producers and smaller integrated companies, with the independents accounting for a large majority in this group.

Altogether, there may be some 18,000 U.S. oil and gas producers according to the U.S. Census Bureau. In 1981, 200 of them, including the 23 majors in our group, accounted for about 90 percent of total U.S. production.

In the 3-year period 1980–82 the 23 majors experienced a small but steady decline in both oil and gas reserves, as the following table shows.

[Table 1 follows:]

TABLE 1. PROVEN RESERVES OF OIL AND GAS AT YEAR-END, 1979–1982

[See note for units of measure]

| | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|
| 23 major companies: | | | | |
| Petroleum liquids | 23,066 | 22,551 | 21,898 | 21,022 |
| Natural gas | 107,698 | 104,503 | 103,987 | 102,377 |
| Liquids and gas total | 41,634 | 40,569 | 39,827 | 38,673 |
| U.S. total: | | | | |
| Petroleum liquids | 36,425 | 36,533 | 36,494 | ([1]) |
| Natural gas | 200,997 | 199,021 | 201,730 | ([1]) |
| Liquids and gas total | 71,080 | 70,847 | 71,275 | ([1]) |
| 23 major companies' share of U.S. total (percent) | | | | |
| Petroleum liquids | 63 | 62 | 60 | ([1]) |
| Natural gas | 54 | 53 | 52 | ([1]) |
| Liquids and gas total | 59 | 57 | 56 | ([1]) |

[1] Not available.

Note: Units of measure: Petroleum Liquids in millions of barrels; Natural Gas in billion cubic feet; Liquids and Gas Total in millions of barrels of oil equivalent (natural gas converted at a rate of 5.8 MCF/bbl.

Sources: Annual reports and Form 10–K of 23 large integrated companies, a list of which is attached as Appendix A; U.S. Department of Energy, Energy Information Administration, "U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves: 1981 Annual Report," DOE/EIA-0216(81), August 1982.

Mr. LICHTBLAU. No industry data are available for yearend 1982 reserves, but from 1979 to 1981 total industry reserves remained approximately unchanged. Thus, the relative position of the majors in U.S. oil and gas reserves declined slightly. At yearend 1982 their oil reserves, crude and NGL's, were equal to 10 times their annual production, which is in line with the industry's reserve/production ratio.

For natural gas the majors' reserve/production ratio was 12.9 compared to the industry's ratio of 11.8. However, the reserves include some 26 trillion cubic feet of natural gas in Northern Alaska, all of which is held by companies in the major group and none of which will have a market outlet in the foreseeable future. If we eliminate the Northern Alaskan gas reserves from our totals, the reserve/production ratios of the majors and the industry as a whole are both close to 9.7.

An important reason for the relative decline in the majors' share of the reserves is the substantial upward revisions in previously discovered reserves, including improved recovery, made by the rest of the industry. In the 2-year period 1980–1981, the industry as a whole revised oil reserves upward by 3.35 billion barrels or 2.2 times as much as the 23 majors and gas reserves upward by 3.65 trillion cubic feet, or 5.4 times as much as the 23 majors.

Revisions of reserves can be either positive or negative. In 1980 the net gas revisions for the majors were in fact substantially negative. They represent corrections for previous overestimates or underestimates of reported proved reserves and, where applicable, improved recovery project and techniques. They result from reexamination of existing geological and engineering information or from new information provided through the drilling of development wells.

The indicated large upward revisions of existing reserves by the nonmajors suggest that this group of companies has continued to concentrate its efforts in the traditional producing regions, which apparently still contain substantial undeveloped oil deposits in known areas. The majors' oil and gas reserves declined by another 4 percent and 1.8 percent respectively in 1982. Total U.S. reserve changes for 1982 are not yet available.

Exploration expenditures of the 23 companies rose by 38 percent in 1981 and 2.4 percent in 1982 to $12.2 billion. Development expenditures showed a similar pattern: a 42-percent increase in 1981 to $13.8 billion and virtually no further increase in 1982. In viewing the leveling off of exploration and development expenditures in 1982 it should be kept in mind that the entire drilling sector of the U.S. oil industry experienced a significant cost deflation last year compared to 1981.

The fact that the proved reserves of the largest, financially strongest and technically most sophisticated oil companies have continued to decline despite the incentives of relatively high resource prices and a ready market for all domestic oil, though not all domestic gas, is evidence of our continuing resource depletion. So is the fact that without the upward "paper" revisions of previously discovered reserves, total U.S. oil and gas reserves would have declined in 1980 and 1981 instead of remaining flat for oil and rising marginally for gas.

The measure of success of the petroleum-producing industry's exploration effort is the "additions to reserves," which are the new reserves found each year and added to existing reserves. These represent the results of the industry's exploration activities, from initial geological surveys to the completion and testing of wells.

Table 3 shows the additions to reserves for the 23 majors and for the industry as a whole.

[Table 2 follows:]

### TABLE 2.—COSTS INCURRED BY 23 MAJOR COMPANIES IN U.S. OIL AND GAS PRODUCING ACTIVITIES (CAPITALIZED AND EXPENSED), 1980–82

[In million dollars]

| | 1980 | 1981 | 1982 |
|---|---|---|---|
| Property acquisition | 8,508 | 8,062 | 5,449 |
| Exploration | 7,184 | 9,914 | 10,154 |
| Development | 9,688 | 13,803 | 13,877 |

Source: Annual reports of 23 large integrated campanies, a list of which is attached as app. A.

Mr. LICHTBLAU. As shown in their annual reports, which excludes the reserves of royalty owners, the majors accounted for 41 percent and 37 percent respectively of total combined additions to oil and gas reserves from drilling in 1980 and 1981. However, these figures understate the true result of their effort, since they found of course also the reserves belonging to their royalty holders. By adjusting for this understatement we find that the 23 companies accounted for 48 percent and 43 percent respectively of total combined additions to U.S. oil and gas reserves in the 2 years under discussion.

The sharp reduction in reserve additions by the majors shown for 1982 was concentrated mainly in the gas sector and may to some extent have reflected the substantial volume of shut-in gas-producing capacity which may have acted as a temporary disincentive to gas exploration.

[Tables 3 and 4 follow:]

### TABLE 3.—ADDITIONS TO PROVEN U.S. RESERVES OF OIL AND GAS FROM EXPLORATORY DRILLING, 1980–82

[See note for units of measure]

| | 1980 | | | 1981 | | | 1982 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Petroleum liquids | Natural gas | Total | Petroleum liquids | Natural gas | Total | Petroleum liquids | Natural gas | Total |
| 23 major companies: | | | | | | | | | |
| As booked | 619 | 5,899 | 1,636 | 701 | 6,703 | 1,857 | 674 | 5,295 | 1,587 |
| Adjusted for royalties | 722 | 6,884 | 1,909 | 818 | 7,822 | 2,167 | 787 | 6,179 | 1,852 |
| U.S. total | 1,449 | 14,473 | 3,944 | 1,925 | 17,220 | 4,894 | (1) | (1) | (1) |
| 23 major campanies' share of U.S. (Total percent) | | | | | | | | | |
| As booked | 43 | 41 | 41 | 36 | 39 | 38 | (1) | (1) | (1) |
| Adjusted for royalties | 50 | 48 | 48 | 42 | 45 | 44 | | | |

[1] Not available.

Note: Units of measure: Petroleum liquids in millions of barrels; natural gas in billions of cubic feet; total (petroleum liquids + natural gas) in millions of barrels of oil equivalent (natural gas at 5.8 MCF/Bbl).

"23 Major Companies, as booked" are the reserve additions as shown by the companies in their annual reports to shareholders and thus exclude the reserves attributed to royalty owners; "Adjusted for royalties" credits the companies with the finding of these royalty reserves, at an assumed royalty share of 1/7.

Sources: Annual reports and Form 10–K of 23 large integrated companies, a list of which is attached as Appendix A; for U.S. Total, U.S Department of Energy, op. cit

### TABLE 4.—DRILLING ACTIVITY IN THE UNITED STATES, 1980–82

[Number of wells completed]

| | 1980 | | 1981 | | 1982 | |
|---|---|---|---|---|---|---|
| | Productive | Total | Productive | Total | Productive | Total |
| 23 major companies: | | | | | | |
| Exploratory | 1,059 | 2,069 | 1,224 | 2,500 | 1,046 | 2,155 |
| Development | 6,416 | 6,859 | 7,586 | 8,097 | 6,659 | 7,230 |
| Total | 7,475 | 8,927 | 8,809 | 10,597 | 7,705 | 9,385 |
| U.S. total, as reported to the American Petroleum Institute: | | | | | | |
| Exploratory | 3,574 | 11,916 | 4,585 | 15,168 | 4,847 | 16,470 |
| Development | 39,182 | 48,929 | 50,980 | 63,370 | 55,404 | 69,330 |
| Total | 42,756 | 60,845 | 55,565 | 78,538 | 59,251 | 85,800 |
| Success rate on all wells (total productive wells as a percent of all wells): | | | | | | |
| 23 major companies | 84 | | 83 | | 82 | |
| U.S. total | 70 | | 71 | | 69 | |

Sources: Annual reports or Form 10–K of 23 large integrated companies a list of which appears as Appendix A; American Petroleum Institute, Quarterly Review of Drilling Statistics for the United States. Classification between exploratory and development wells may differ for these two sets of data.

Mr. LICHTBLAU. To put the additions to oil and gas reserves into their proper perspective we must determine the effort that went into finding them and the success of this effort. As we have said, the reserve additions under discussion here are the result of exploratory drilling.

In the last 3 years the 23 majors in our group drilled an annual average of 2,241 exploratory wells. The volume of oil found per exploratory well by the majors is substantially higher than that for the industry as a whole. These 23 companies found their 48 percent and 43 percent share of total new U.S. reserves in 1980 and 1981 by drilling only 10 to 15 percent of all U.S. exploratory wells, depending on which source is used for the U.S. total.

Their discovery volume per exploration well was therefore nearly three times as high as that of the industry as a whole: 870,000 barrels of oil equivalent for the majors versus 326,000 barrels for the entire industry. Earlier studies show approximately similar difference for the late 1970's.

[Table 5 follows:]

### TABLE 5.—DOMESTIC RESERVE ADDITIONS PER WELL

[Thousands of barrels of oil equivalent]

| | 1980 | 1981 | 1982 |
|---|---|---|---|
| Additions per exploratory well: | | | |
| 23 major companies, adjusted for royalties | 923 | 867 | 859 |
| U.S. total | 331 | 323 | (1) |
| Additions per total well: | | | |
| 23 major companies, adjusted for royalties | 214 | 204 | 197 |
| U.S. total | 65 | 62 | (1) |

[1] Not available.

Sources: Reserve additions: See table 3. Wells completed: See Table 4.

Mr. LICHTBLAU. It should be pointed out that the definition of exploratory wells may be somewhat different for companies reporting under SEC regulations, such as the 23 majors, than for the industry's voluntary reports to the American Association of Petroleum Geologists and the American Petroleum Institute. If, however, the reserves additions of the majors and the industry as a whole are each related to the total number of wells drilled, thereby eliminating any classification differences between exploratory and development wells, the finding rate of the majors in 1980 and 1981 would still have been about three times that of the industry.

The reason for the consistently higher finding rate of the majors appears to be that they operate far more than the independents in high cost, high risk, and high reward areas such as Alaska, the continental shelf, and the Western Overthrust Belt. They also generally drill deeper wells, which increases costs exponentially. As we found in our earlier surveys, in 1979 and 1980, the majors' exploratory wells were 65 percent and 59 percent deeper than the industry average.

The higher cost of the wells drilled by the majors cannot be readily computed from their annual reports since their reported epxloration expenditures in a given year are not necessarily related directly to their reported wells drilled in that year. However, the Census Bureau report shows that in 1981 drilling and equipping expenditure per exploratory well averaged $711,000 for the industry, but $2.4 million for the 16 largest companies, most of which are presumably in our group of 23.

While the difference in expenditure cannot be directly related to the earlier discussed difference in the finding rate, it is clear that the major oil companies spend substantially more money and find substantially more oil per well drilled than the rest of the industry. Their relatively small share in the total number of exploratory wells drilled must be viewed with these facts in mind.

Altogether, then, it appears that the major oil companies and the independents perform somewhat different but complementary functions in finding and developing U.S. oil and gas reserves. The majors, while active in all areas, are increasingly moving into the less accessible, unexplored parts of the Outer Continental Shelf, in deeper and tighter reservoirs onshore in the lower 48 States and in the Arctic region. The capital and technical requirements to locate and develop these resources are generally beyond the capability of the independents. The primary discovery function of the latter will remain the location of the remaining reserviors in the historic onshore and offshore areas and the extension of existing reserves by improving their recovery rates. To arrest our continuing resource depletion will undoubtedly require maximum efforts by both groups.

[Appendix A follows:]

## APPENDIX A

### LARGE INTEGRATED COMPANIES INCLUDED IN DATA FOR 23 MAJOR COMPANIES

Amerada Hess Corp.; Atlantic Richfield Co.; Champlin Petroleum Co.; Cities Service Co.; Coastal Corp.; Conoco Inc. (DuPont); Diamond Shamrock Corp.; Exxon Corp.; Getty Oil Co.; Gulf Oil Corp.; Marathon Oil Co. (U.S. Steel); and Mobil Corp.

Murphy Oil Corp.; Pennzoil Co.; Phillips Petroleum Co.; Shell Oil Co.; Standard Oil Co. of California; Standard Oil Co. (Indiana); The Standard Oil Co. (Ohio); Sun Co.; Tenneco Inc.; Texaco Inc.; and Union Oil Co. of California.

Mr. **Pickle**. Thank you, Mr. Lichtblau. We appreciate your statement.

Mr. Anthony, Mr. Dorgan, any questions?

Mr. **Anthony**. On page 12 of your statement, you talk about the major oil companies going into the less accessible unexplored parts of the outer continental shelf, in deeper and tighter reservoirs in the lower 48 States and the Arctic region. Then you say that the independents seem to be doing a somewhat different function but complementary to finding and developing oil.

Many, many of the witnesses yesterday indicated basically the very same thing. Drilling into wells in existing reservoirs had proven unprofitable to the majors, and had been abandoned. The independents had purchased these wells from the majors and then had gone in and reworked those wells. They would use secondary, tertiary recovery, or go in and drill exploratory wells in a defined geological formation, finding some additional oil. I assume what you are saying is that encouraging them to do this is good energy policy.

Mr. **Lichtblau**. Yes, definitely good energy policy, particularly since we see our oil and gas resources continue to decline.

Mr. **Anthony**. Continue to decline?

Mr. **Lichtblau**. Yes, sir.

Mr. **Anthony**. If we continue to decline, we are just going to be more dependent upon an alternate source of energy, which we are failing to produce in this country, because of the leadership out of the White House?

Mr. **Lichtblau**. I don't know about the leadership of the White House——

Mr. **Anthony**. Over the last 2 years they have been trying to destroy all of the programs that we have had.

Mr. **Lichtblau**. In alternate energy?

Mr. **Anthony**. Yes. They haven't been very supportive.

Mr. **Licht**[illegible] You are correct in that, Congressman, but the situation ha[illegible]ed from what it was.

Mr. **Ant**[illegible] they do is put us in more peril as far as foreign oil i[illegible]ort[illegible]oncerned.

Mr. **Li**[illegible]**tb**[illegible], Congressman, I would agree. Of course, foreign oil impor[illegible]clined very substantially in the last 2 or 3 years, from [illegible]cy of 48 percent back in 1977, we are now down to ab[illegible]percent, which is a remarkable drop. But that drop h[illegible] come about not because we have found more oil domestically [illegible]ut because we are using less oil and gas domestically.

Mr. **Anthony**. It came about as a result of a recession?

Mr. **Lichtblau**. A recession and also conservation.

Mr. **Anthony**. Conservation.

Mr. **Lichtblau**. Substitution of oil by other energy sources, but it has not come about as the result of finding more oil and gas, relative to our requirements.

Mr. **Anthony**. The point I am trying to make is, in your opinion, do you see justification for the Federal Government, through its tax policy to encourage independents to continue to go into areas that the majors have abandoned, where proven reserves can be found and added to our reserves?

Mr. LICHTBLAU. My opinion would be that both these groups, the majors and the independents, have to work at their maximum effort in order to maintain our oil reserves or prevent them from dropping too rapidly. That requires a policy encouraging the majors, and the independents to go into these areas.

I am not specifically talking about any tax measure, but in general I think the independents are required to fulfill this particular function which no other segment of the industry does; and the majors obviously have to fulfill theirs, so there is no conflict between the two groups.

Mr. ANTHONY. Let me put it in a more basic way. Are you opposed to tax incentives to encourage this type of activity?

Mr. LICHTBLAU. I would like to stay away from that particular answer, because we are not taking a position on the tax debate in this committee. My personal view, if you want to have it——

Mr. ANTHONY. We encounter witnesses all the time who would rather not take positions. So don't feel that you have to.

Mr. LICHTBLAU. Let me say that if there was a time to change these laws, it would have been in the past when the oil industry was doing extremely well because of very sharply increasing prices and all the incentives that you could possibly imagine existed. This is no longer the case. 1983 is not a good year for the U.S. oil industry.

Independents are going bankrupt all over the West and Southwest, and funds for exploration are much less than they were. So to make a change at a time when the industry is not well off is certainly not desirable from a national resource policy point of view. What should have been done 2 or 3 years ago is another matter.

Mr. ANTHONY. That sounds beautiful and I appreciate the statement.

Mr. PICKLE. Mr. Dorgan.

Mr. DORGAN. I have no questions.

Mr. PICKLE. Before you leave, just for the record, you and your company have been commissioned by the Petroleum——

Mr. LICHTBLAU. Petroleum Industry Research Foundation.

Mr. PICKLE. And you represent 23 of the major companies?

Mr. LICHTBLAU. No, sir. I don't represent them. We used the sample of 23 major companies.

Mr. PICKLE. You made a study for those companies?

Mr. LICHTBLAU. Not for them, no. We made this particular study that we are talking of here this morning for this hearing today.

Mr. PICKLE. For the hearing today?

Mr. LICHTBLAU. Yes. We just took 23 major oil companies. We took their annual reports and looked at the numbers in the annual reports. It was not commissioned by them to do this particular paper which I am submitting here.

Mr. PICKLE. And your statement then is primarily an analysis?

Mr. LICHTBLAU. Yes.

Mr. PICKLE. Of the exploration activities of these companies?

Mr. LICHTBLAU. Yes.

Mr. PICKLE. Not with respect to taxes?

Mr. LICHTBLAU. That is correct.

Mr. PICKLE. Thank you very much, sir.

Mr. LICHTBLAU. Thank you.

Mr. **Thomas**. Mr. Chairman, I apologize for being late. Did we establish who funds Petroleum Industry Research Foundation?

Mr. **Pickle**. I did not ask that. Mr. Thomas has a question for you.

Mr. **Thomas**. From where does your funding come?

Mr. **Lichtblau**. Oil companies.

Mr. **Thomas**. Which oil companies?

Mr. **Lichtblau**. Marketing companies, independent refiners, individual oil companies.

Mr. **Thomas**. And individual oil companies?

Mr. **Lichtblau**. Yes.

Mr. **Thomas**. The last page of your testimony has a listing of large integrated companies. Do all of those or some of those——

Mr. **Lichtblau**. Some of those are contributors.

Mr. **Thomas**. Which ones?

Mr. **Lichtblau**. I would think the majority of them. Most of them are, probably. In fact, I am sure most of them are. But, as I say, this study was not done on their behalf. We just took the annual——

Mr. **Thomas**. I am just trying to find out who you are.

Mr. **Lichtblau**. Oh, I thought you knew.

Mr. **Thomas**. What percentage of the funding comes from the large——

Mr. **Lichtblau**. Pardon me?

Mr. **Thomas**. What percent of the funding of your foundation comes from the large companies versus the refiners and the independents that you mentioned?

Mr. **Lichtblau**. I really don't know offhand, Congressman. I would say the bulk comes from integrated oil companies, but a substantial amount from independent refining companies and also from marketing, oil marketers on the east coast.

Mr. **Thomas**. How long have you been in existence?

Mr. **Lichtblau**. About 30 years, 25 years.

Mr. **Thomas**. Say about 30 years?

Mr. **Lichtblau**. Yes, since the early 1950's.

Mr. **Thomas**. What was the reason for the creation of the foundation?

Mr. **Lichtblau**. At one time we were very much involved in the oil import debate, but this has no longer been an issue for many years.

Mr. **Thomas**. You were there and you became kind of a clearinghouse for information and research?

Mr. **Lichtblau**. Yes, and we still issue reports and talk to the press a great deal, and we analyze. I just did a forecast of world oil supply and demand in the year 2000, which I am sure is going to be correct.

Mr. **Thomas**. And people subscribe to your foundation for information?

Mr. **Lichtblau**. No.

Mr. **Thomas**. They give grants to you?

Mr. **Lichtblau**. Grants. They contribute annual sums.

Mr. **Thomas**. Do you have a board of directors?

Mr. **Lichtblau**. Yes.

Mr. THOMAS. That determines what you do in a given year in various research projects?

Mr. LICHTBLAU. May I say our board of directors is made up entirely of independent marketers, none of the major oil companies are on it.

Mr. THOMAS. Thank you very much. Thank you, Mr. Chairman.

Mr. PICKLE. Thank you, sir.

Our next panel will consist of Mr. John J. McKenna, Mr. Arthur L. Smith, and Jaye F. Dyer. Are those individuals with us this morning? Our first witness will be Mr. John J. McKenna, vice president—investment banking, Dean Witter Reynolds, Inc., Houston, Tex. Next will be Mr. Arthur L. Smith, vice president, research, Oppenheimer & Co. of New York. Then the next will be Mr. Jaye Dyer, president of the Dyco Petroleum Corp., Minneapolis. You have with you Mr. Robert R. Nathan, who is a consultant and chairman of Robert Nathan Associates. We have had Mr. Nathan with us before.

We will ask each of you now to proceed. Mr. McKenna, will you commence your testimony. We are going to ask each of you to summarize your statements within the confines of 5 minutes, and we will try to abide similarly so that we might get your testimony on the record.

Mr. McKenna, will you proceed?

## STATEMENT OF JOHN J. McKENNA, VICE PRESIDENT, INVESTMENT BANKING, DEAN WITTER REYNOLDS INC., HOUSTON, TEX.

Mr. McKENNA. Thank you, Mr. Chairman. My comments will be in the context of the lackluster state of the capital formation for independent oil and gas companies, the effect that this has had on the reduced activity in the industry and the linkage with respect to investors' perception in this industry, the tax treatment available to investors, and the ultimate discovery of additional oil and gas in the United States.

One would be hard pressed to find as dramatic a transition from boom to gloom as had occurred in the independent energy sector over the past year. The buildup from 1975 to 1981 of investor enthusiasm for energy-related issues followed by the subsequent period of disenchantment was perhaps more dramatic but not unlike past market cycles in such areas as conglomerates, REIT's, and savings and loans.

In the 1971 period, operators who overpaid for leases, equipment, reserves, and people were bailed out by an 800-percent increase in oil prices and an even greater increase in natural gas prices. Those days are over and the fundamentals have altered dramatically. Today's lower oil prices and reduced gas takes by the pipelines have not only dampened investment enthusiasm, but also have severely reduced cash flows, leaving independents in a precarious financial situation. Access to capital has become the major stumbling block.

In the wake of the Penn Square failure and loan losses of other major institutions, banks have become increasingly cautious of reserve base loans, common equity prices have declined to a fraction of their highs in 1980 and 1981 which has effectively closed access to this market. Limited partnership funds have been very difficult to raise.

Independents who have borrowed money to budget their future on the basis of $50 to $60 per barrel and $7 to $8 per MCF natural gas prices are now faced with the option of either going bankrupt or selling off assets to stay alive. Bankruptcies in the U.S. oil and gas industry are now common newspaper headlines. In the southern district of Texas alone there were 165 bankruptcies of energy companies announced since January 1, 1982.

Those companies who are attempting to sell assets are confronted by the current market price of approximately $7 per net equivalent barrel as opposed to approximately $11 per barrel, a decline of 36 percent. The recent decline in interest rates buys time for a number of financially troubled companies, but it does not solve the basic problem of capital infusion into this industry.

Liquidity and access to capital have now become the most important issues. Our experience with retail, institutional, and corporate investment programs points to a wait-and-see posture by investors as they observe the industry shakeout. There is a pronounced flow of funds away from exploration into safer albeit less rewarding investment in income funds.

Within the category of programs characterized as drilling funds, there has been a trend toward development rather than exploratory programs. The industry will continue to be perceived as weak from a credit standpoint. Oil and gas companies which desire to access public and private markets will have to make sizable concessions relative to nonenergy industries by way of paying higher rates for debt and suffering lower price/earnings ratios.

In my written statement supplied for the record, I have summarized venture capital, oil, and gas programs, institutional investment, new financial vehicles, and commercial bank financing. I won't go into the particulars here, but I would like to mention what is happening in the oil and gas program sales business, and particularly the sale of drilling and development programs which is a major portion of financing for independents.

The consequences of reduced capital formation has led to a reduction in drilling activity. From a financial standpoint, we suggest that there is a linkage among capital formation, drilling activity, and discovery of oil and gas. To the extent that this uncertainty exists in the mind of the investor with respect to the assumption he uses to justify his investment, this uncertainty will cause him to look for alternative investments.

At the present time, numerous uncertainties exist in the oil and gas industry, one of which is the Tax Code. To the extent that changes are made or even the perception of change exists in the industry, investment dollars will flow to other projects and industries where the underlying assumptions are less prone to risk.

Mr. Chairman, I have attempted to explain the current state of the investment market for independent oil and gas companies. At the present time the principal deterrent to capital formation in this industry is uncertainty. If the market perceives a change in the tax treatment for oil and gas producers, we believe this will be one of the key factors for continued disruption between the linkage of capital formation and the discovery of oil and gas.

The result might very well be a pronounced reduction in the number of independent oil and gas companies, a further decline in wells drilled, a reduction of U.S. reserves, and a further reliance on offshore soures of oil and gas. Thank you very much.

Mr. PICKLE. We thank you.

[The prepared statement follows:]

### STATEMENT OF JOHN J. MCKENNA, VICE PRESIDENT, INVESTMENT BANKING, DEAN WITTER REYNOLDS INC., HOUSTON, TEX.

Mr. Chairman and Members of the Subcommittee: My name is John J. McKenna. I am a Vice President in the investment banking department of Dean Witter Reynolds Inc. and am Manager of our firm's Energy Group office in Houston. I am pleased to have this opportunity to testify before the House Subcommittee on oversight with respect to hearings on the tax treatment of producers of oil and gas. My comments will be within the context of the lackluster state of capital formation for independent oil and gas companies, the effect this has on reduced activity in the industry and the linkage with respect to the investors' perception of the industry, the tax treatment available to investors and the ultimate discovery of additional oil and gas in the United States. My appearance in front of the Subcommitte should be recognized as a response to the financial issues involved in the independent oil and gas industry and not as a statement on the Administration's energy, fiscal or budget policies. I also propose to limit my comments to investment banking issues only and not address specific Internal Revenue Code provisions.

One would be hard pressed to find as dramatic a transition from boom to gloom as has occurred within the independent energy sector over the past year. The buildup from 1975 to 1981 of investor enthusiasm for energy-related issues followed by the subsequent period of disenchantment was perhaps more dramatic, but not unlike past market cycles in areas such as conglomerates, REITs, and savings-and-loans. In the 1971 period, operators who overpaid for leases, equipment, reserves, and people were bailed out by a 800% increase in oil prices and an even greater increase in natural gas prices. Those days are over and the fundamentals have altered dramatically. Today's lower oil prices and the reduced gas takes by the pipelines have not only dampened investor enthusiasm but also have severely reduced cash flows, leaving the independents in a precarious financial situation. Access to capital has become a major stumbling block. In the wake of the Penn Square failure and the loan losses of other major institutions, banks have become increasingly cautious of reserve-based loans. Common equity prices have declined to a fraction of their highs in 1980 and 1981 which has effectively closed access to this market. Limited partnership funds have also been very difficult to raise.

Independents who have borrowed money and budgeted their future on the basis of $50–60 per barrel oil and $7–8 per MCF natural gas prices are now faced with the option of either going bankrupt or selling off assets to stay alive. Bankruptcies in the U.S. oil and gas industry are now a common newspaper headline. In the Southern District of Texas alone there were 165 bankruptcies of energy companies announced since January 1, 1982. Those companies who are attempting to sell assets are confronted with a current market price of approximately $7 per net equivalent barrel, as opposed to approximately $11 per barrel last summer, a deline of 36 percent. The recent decline in interest rates buys time for a number of financially troubled companies, but it does not solve the basic problem of capital infusion into the industry.

Without a doubt, the changing environment can best be characterized as a shift of focus, from operational issues including:

1. Rig and pipe availability;
2. Cost of prospects;
3. Quality and efficiency of daily activities; which were paramount in 1980 and 1981, to the financial and marketing issues of today including:

1. Liquidity;
2. Access to capital;
3. Ability to sell product.

Liquidity and access to capital have now become the most important issues. Our experience with retail, institutional and corporate investment programs point to a "wait and see" posture by investors as they observe the dynamics of the current industry shakeout. There is a pronounced flow of funds away from exploration to a safer, albeit less rewarding investment in income funds. Within the category of programs characterized as drilling funds, there has been a trend toward developmental as opposed to exploratory programs. The industry will continue to be perceived as weak from a credit standpoint. Oil and gas companies which desire to access the public and private markets will have to make sizeable concessions relative to non-energy related industries, both by way of paying higher rates on debt instruments and suffering greater dilution due to low price-earnings ratios. Allow me to briefly summarize the situation.

1. *Venture Capital.*—A leading oil and gas venture capitalist predicted that only about 10 transactions will be done in 1983—maybe as few as 5 transactions. These will be in the form of convertible preferred stock with small public companies. Each transaction will be small (in the range of $5–10MM) and will result in the venture capitalist virtually controlling the company after the transaction. Proceeds of the offering will be used to reduce bank debt and therefore, little or no new money will be invested in the business.

2. *Oil and Gas Programs*—Sales of oil and gas exploration and development programs have declined significantly. Total funds raised for exploration and development in 1982 totaled $1.07 billion versus $2.03 billion in 1981 (a reduction of 47 percent). In 1983 we estimate the total amount raised to be in the range of approximately $450 million (a further reduction of 58 percent). One area of tremendous growth however has been the sale of income funds where the reduction in risk results in greater cash flow to the investor but generally little or no opportunity for significant upside potential which is found in the pure exploratory play. Statistics for the income fund side of the market indicate that $1.25 billion was raised in 1982 versus $874 million in 1981 (an increase of 60 percent). We forecast that in 1983, $1.8 billion will be raised in income funds (an increase of 44 percent). It should be noted that income funds do not generate the same level of activity with respect to finding new oil and gas deposits as do exploration and drilling funds. Income Funds are used to purchase existing oil and gas properties and generally act as a transfer of wealth from working interest owners to the new partnership.

3. *Institutional Investment*—This is a very hard number to estimate because most transactions are private and therefore we cannot keep records on who raised money, how much it was and who the sources were. One barometer of activity is the number of insurance companies willing to make equity related or drilling investments in the exploration business. In 1981 we counted 15 major institutions (out of a total of 20); in 1982 the figure was 10 and in 1983 we predict that only about 5 institutions will want to review oil and gas transactions.

4. *New Financing Vehicles*—There is a relatively new form of financing being conducted in which the institution (often a pension fund or comingling of money pools) will advance funds as a loan, a low interest debenture, a land acquisition fund or in a drilling fund. Their return will be in a combination of a fixed interest rate plus an overriding royalty or a form of carried interest. There has been increased interest in this form of financing; however, many individuals running these funds are ex-bankers who still rely on the concept of lending against proven producing properties and other benchmarks of traditional oil and gas loans. As you can expect, this is of little comfort to a company trying to raise equity money.

5. *Commercial Bank Financing*—Following the collapse of the Penn Square Bank and other recent announcements of bank loan losses in their energy portfolios, major U.S. banks have adopted many new policies. These include stringent loan guidelines for oil and gas companies, changes in pricing assumptions, discount rates, and loan to reserve value ratios. In reaction to this concern about general creditworthiness, many banks have all but eliminated traditional financing for the independent.

Historically, independents have relied heavily on these external sources of funds. In 1981, the IPAA estimates that independents spent $32.7 billion for exploration and development, while they took in $28.0 billion in production revenues, a gap of $4.7 billion.

The consequences of reduced capital formation, falling oil and gas prices and the recession will lead to a reduction in drilling activity. The rig report of April 25, 1983, indicated that there were 1,860 rigs operating, compared to 3,310 rigs operating at April 18, 1982 (a 44 percent reduction); I would conclude that exploratory activity has fallen off dramatically. We need to remember the old axiom in this industry which is: "He who drills more wells finds more oil."

The reduction in demand for natural gas, as a result of the recession, has caused a temporary surplus and consequently a soft gas market. This is truly a short-term situation. The proven natural gas inventory in the United States has declined from

265 Tcf to 202 Tcf during the period 1970–1981. Also during that time, production and the reserves-to-production ratio have declined, as has the amount of gas found per successful gas well drilled, while total drilling has almost tripled, and the number of successful gas wells drilled has more than quadrupled. The inevitable situation is that if we do not act now to stem this fall in the surplus oil and gas available to the United States, our economic recovery and national security might very well be hampered by inadequate sources of supply.

From a financial standpoint we suggest that there is a linkage among capital formation, drilling activity, and discovery of oil and gas. To the extent that uncertainty exists in the mind of the investor with respect to the assumptions used to justify his investment, this uncertainty will cause him to look for alternate investments. At the present time, numerous uncertainties exist in the oil and gas industry, one of which is the tax code. To the extent that changes are made or even the perception of change exists in the industry, investment dollars will flow to other projects and industries where the underlying assumptions are less prone to risk.

Mr. Chairman, I have attempted to explain the current state of the investment market for the independent oil and gas industry. At the present time, the principal deterrant to capital formation in this industry is uncertainty. If the market perceives a change in the tax treatment for oil and gas producers, we believe that this will be one of the factors which will continue to disrupt the linkage between capital formation and discovery of oil and gas. The result might very well be a pronounced reduction in the number of independent oil and gas companies due to an increase in bankruptcies, a further decline in wells drilled, a reduction in U.S. reserves and a further reliance on offshore sources of oil and gas.

This concludes my prepared statement. I would be pleased to respond to any questions that the member of the Subcommittee might have.

Mr. PICKLE. Now Mr. Arthur Smith.

## STATEMENT OF ARTHUR L. SMITH, VICE PRESIDENT, RESEARCH, OPPENHEIMER & CO., INC., NEW YORK, N.Y.

Mr. SMITH. Thank you, Mr. Pickle. For the past 7 years, I have been wholly concentrating my efforts on the analysis of the oil industry, and I have applied research and recommendations to the clients of my firm on the specific attractiveness of those investments. As you have heard before, the independent oil sector is in extremely poor financial condition.

In many ways my testimony is complementary to that of Mr. McKenna. Because the petroleum output of the independent oil producers is heavily skewed toward natural gas—rather than oil—the gas "bubble" is a greater problem for these companies than the major oils—whose output is weighted to oil. The gas market, as you have heard, is extremely depressed with 20 percent or greater curtailments for many producers; right now the industry is probably at the low point of a bust.

The point is that the oil industry is very cylical. We have seen cycles before but I think this one is noteworthy for its amplitude. Work I have done on analysis of the industry shows that the current debt load carried by the independents is a crippling burden. Many companies are facing an outlook where their interest expense on outstanding debt balances is equivalent to or very close to their cash flow from operations.

The reason many oil producers arrived at such a dire position, was that they responded to the incentives for resource development in 1980–82; in many ways, the industry was fulfilling its mission for the national interest.

The companies I looked at in a screen of independent producers showed that on average these companies were carrying long-term debt balances equivalent to about 60 percent of their market value.

That is a very high level. Also the oil service industry, particularly drilling contractors, are in a position where they are carrying as much as 90 percent or above in terms of their debt.

The Penn Square Bank failure, as you know, last July 5, caused a dramatic reversal in the way the banking industry deals with the oil industry. In the past 12 to 18 months, there have been numerous bankruptcies, but more than that, the banks have really turned the screws on the smaller companies. While the economy is recovering, I believe that the upturn is unlikely to provide much benefit to these companies in the short run.

Many companies which are being helped by the banks today, and are on "heart and lung machines," run the risk of having the plug pulled in the next few months. I expect to see a continued increase in the number of bankruptcies which are announced.

An econometric model developed by Dr. Edward I. Altman of New York University's Graduate School of Business computes a series of ratios which then can predict bankruptcies among publicly traded companies called the Z score. When I recently ran this financial ratio analysis, I found that 85 companies—35 percent—in a screen of 235 independent producers were in danger of failure.

With respect to the differential tax treatment in the industry, I think that possible tax reductions today would be akin to changing the rules in the middle of the game. The companies that are now suffering financial difficulties pursued those resource development programs given a certain set of assumptions on prices and taxation.

If tax policy is changed, I think it should have a devastating effect on this industry. It should be noted that we are dealing with a mature industry where it is very difficult to find large accumulations of oil or gas at any cost. In sum, I do think the incentives have had their desired effect.

Thank you.

[The prepared statement follows:]

## STATEMENT OF ARTHUR L. SMITH, VICE PRESIDENT; RESEARCH, OPPENHEIMER & CO., INC.

I am pleased to appear before this subcommittee today to discuss my views on the current financial condition of the domestic independent oil and gas producers and the numerous factors that legislators must consider in evaluating possible changes in the tax incentives currently in place for independents.

The purposes of my statements are to comment on:

(1) The significant role independent oil companies play in domestic energy resource development and production;

(2) The poor financial plight of the majority of independent producers today;

(3) The likelihood that business failures among small oil and gas producers and oil service companies will continue to rise throughout 1983;

(4) The negative impact on resource development that tax increases or legislative uncertainty could have.

### The Role of Independent Oil Producers

The table below demonstrates the significance of the small independents in United States exploration and development activity among the universe of domestic oil producers. According to a survey of the industry by a major oil service company, major integrated oil companies and the top 100 large independent producers account for a mere 1% of total operators and drill 17% of total domestic wells. The large companies account for a disproportionate share of total drilling expensive expenditures (more than 51%) due to their emphasis on expensive "frontier" exploration (Alaska, the Rocky Mountain Overthrust Belt) and activity in the offshore oil basins (primarily the Gulf of Mexico).

The more than 10,000 smaller independent oil producers represent roughly 99% of total United States oil companies and drill 73% of domestic wells. Collectively the multitude of small independent oil companies account for a very meaningful 49% of total drilling expenditures.

Table I

Distribution of Activity in the United States

| | % of Total Operators | % of Wells Drilled | % of Expenditures |
|---|---|---|---|
| Majors | 0.2% | 11.0% | 25.2% |
| Top 100 Independents | 0.9 | 15.6 | 26.2 |
| Next 200 Independents | 1.8 | 12.1 | 15.1 |
| All Other Independents | 1.8 | 7.6 | 6.9 |
| (9-10,000) | 95.3 | 53.7 | 26.6 |

Source: Smith International, Inc.

## Independent Oil Producers Are Heavily Dependent On Natural Gas

It is noteworthy that the domestic petroleum reserves and production of independent oil producers are heavily skewed toward natural gas. A survey we performed of the top 18 large integrated domestic and international oils showed that these giant companies collectively accounted for roughly __% and __% of total domestic proven oil and natural gas reserves, respectively, in 1981. Moreover, our analysis show that the giant oils were responsible for __% of domestic petroleum liquids output and __% of natural gas production that year. This data indicates that all other domestic producers, the more than 10,000 independent oils, derive a disproportionate share of their production and cash flow from natural gas reservoirs.

A significant supply/demand imbalance exists in the United States and Canadian natural gas markets today. Rising producer gas output capability coupled with a 9.3% decline in natural gas consumption in the United States last year (down 1.9 trillion cubic feet to 18.5 TCF) implies that domestic producers are experiencing natural gas production curtailments of 20% or more. Many gas pipelines are refusing to hook up new supplies and pricing escalation under the Natural Gas Policy Act is resulting in the delivered price of natural gas to many consumers in excess of the competitive BTU equivalent price of residual fuel oil. The Administration's natural gas decontrol bill is viewed as a major disappointment to most independent natural gas producers.

Soft natural gas demand and gas pricing uncertainty is exacerbating the slump in the oil patch. The Subcommittee on Oversight should be aware that reductions in tax incentives now available to independent oil operators would further weaken an industry that is experiencing enormous financial difficulties.

## The Illiquidity of Independent Oil Producers

Since the celebrated failure of Oklahoma's Penn Square Bank last July 5th, much has been written in the financial press about the crippling debt burdens of many small independent producers and oil service companies. Excessively permissive lending terms by bankers to the energy sector allowed many oil producers to over-leverage their existing reserve bases as their appetite for increased spending on domestic exploration and development activities vastly outstripped internal cash flow generation. It should be noted that oil company managements were responding to incentives put in place by the Congress to stimulate petroleum resource development; a goal which was in the National interest to reduce our dependence on foreign petroleum imports. Today, independent oil producers are suffering reduced cash flows from existing producing properties due to the gas surplus and lower domestic liquid prices.

Problem loans to energy companies have forced a number of bank consolidations--Abilene National, and recently, Seattle First--and many banks have continued to set aside sizable loan loss provisions--Continental Illinois, Interfirst, et. al.--to reflect bad debts to energy companies. There is little doubt that the 1979-1981 oil industry exploration "boom" brought out speculative excesses, i.e., inexperienced operators, and the subsequent "bust" is causing a painful correction and consolidation phase. The oil industry has experienced numerous dramatic cyclical swings during its history; the most recent is noteworthy for its amplitude.

Notwithstanding the recent welcome plunge in interest rates charged to independent oil companies holding floating rate debt, conditions remain desperate for many independent oil operators. Not surprisingly, the banking industry has turned the screws on small oil operators in the wake of the Penn Square failure. Unfortunately, the banking excesses of the recent past will cause the pendulum of banking relationships with small oil operators to swing beyond the appropriate level. Many debt-heavy oil companies are not only being forced to live within their cash flow from operations, but also must set aside funds to retire outstanding debt balances.

## How Severe Is The Independent Oil Industry's Debt Crisis?

For the most part, the economic recovery now underway in the United States will do little to alleviate the small oil producers' financial problems in the short run. In fact, we anticipate a sharp increase in the failure rate among small oil producers and oil service companies during 1983. This expectation stems from our work in financial and liquidity analyses of independent oil companies which demonstrates that a high percentage of these firms are on "heart and lung machines" by their bankers today. Now that banking industry profitability is on the rise, lending institutions are likely to act in a traditional manner--cutting loose on weak clients now that economic recovery is taking place and write-offs can be largely offset against improved operating results. In the early months of 1983, we have observed a large number of reports of small oil and oil service firms filing for protection from creditors under Chapter 11 of the Bankruptcy Code.

## The Debt Load Leaves Little Breathing Room

An analysis we performed of 170 publicly traded independent oil companies highlights the financial squeeze that is now afflicting the independent oil sector. Since the stock market peak for oil shares in November 1980, this universe of companies has plunged in value by nearly 50%, surrendering more than $38 billion of market value. (Market value--stock price times shares outstanding--is used as our proxy for true "equity".) In their attempt to expand proven petroleum reserves and increase oil and gas output, these independent oil companies took on $6.7 billion of additional long-term debt, causing their effective financial leverage to surge. Long-term debt as a percent of market capitalization soared from a comfortable 18% level in late 1980 to a troublesome 61% level today. (See Table 2 below.)

## Table II

### Market Performance and Financial Leverage
### (November, 1980 Peak to Present)

| Sector | Number of Companies In Sector | Market Capitalization ($ Billions) Peak 11/30/80 | Market Capitalization ($ Billions) 4/27/83 Current | Market Capitalization ($ Billions) Percent Change 11/30/80-Present | Long-term Debt ($ Billions) 11/30/80 | Long-term Debt ($ Billions) Current | Long-term Debt ($ Billions) Percent Change 11/30/80-Present | Debt to Market Capitalization Ratio 11/30/80 | Debt to Market Capitalization Ratio Current |
|---|---|---|---|---|---|---|---|---|---|
| Crude Petroluem & Natural Gas | 170 | $ 79.1 | $ 32.2 | (59.3) | $12.7 | 19.5 | 53.5 | 16.1 | 60.6% |
| Drilling Oil & Gas Wells | 37 | 14.7 | 5.0 | (66.0) | 2.6 | 4.5 | 73.1 | 18.0 | 90.0 |

Similar dire financial straits are affecting the domestic contract drilling sector. An anemic level of active drilling rigs operating in the United States is causing many companies to fight for survival in today's depressed oil drilling market. From the peak in domestic drilling activity of 4,530 active rigs at year-end 1981, more than 2,700 rigs have been idled as activity has fallen a spectacular 60%. Last week fewer than 1,900 rigs were active in the United States, a four year low. (See Addendum.) As shown in the table above, the 37 drilling companies we analyzed had an alarming 90% debt to market capitalization ratio.

## Summary and Conclusion

Most studies of the capital spending pattern of small independent oil companies have shown that these firms have traditionally plowed back the bulk of their cash flow from operations into ongoing exploration and development operations. For this reason, tax and other incentives which have been made available to these companies by the Congress have had their desired effect in stimulating increased domestic energy resource development.

The independent oil producers are currently crippled by an onerous debt burden which was taken on during the past several years to finance exploration and development expenditures well in excess of internally generated cash flow. Given the negative fundamental developments of late--the gas "glut" and the drop in oil prices--it will take several years for many companies to reliquify their excessively debt burdened balance sheets. Any reduction or removal of existing tax incentives available to independent oil producers would be viewed as "changing the rules in the middle of the game" and would cause great hardship among the independent oil sector and would further delay the industry's ability to return to financial health.

Independent oil companies play a very meaningful role in domestic petroleum resource development. Any reduction in the incentives available to these companies could exacerbate the pronounced "shakeout" in the industry which is currently underway. In addition, the repercussions of legislative changes which could reduce independent oil company petroleum drilling activity would impact the domestic oil service industry negatively. These companies are also suffering greatly from the oil sector's poor fundamentals.

In our opinion, proposed changes in incentives available to independent oil operators must be viewed in the context of a "Master Plan" for strategic long-term optimal use of the domestic energy resource base. Legislative uncertainty has traditionally been responsible for stacking a large number of drilling rigs which otherwise would be employed.

In the addendum to this presentation we have included a computer-generated financial analysis of a large universe of independent oil producers and oil service companies. The data contained therein provides a god cross-section of the oil sector and points up the financial difficulties facing many small oil companies today. While this survey does not canvass the entire independent oil industry (since the lion's share of such firms are private and data is not available) it does lend support to our contention that this industry is extremely financially constrained. The Oversight Committee should take this factor into consideration in its deliberations on the issue of differential tax incentives affecting these companies.

I would be happy to answer any questions you might have on my testimony.

# ADDENDUM

## OIL INDUSTRY LIQUIDITY SCREEN

> *"October. This is one of the peculiarly dangerous months to speculate in stocks. The others are July, January, September, April, November, May, March, June, December, August and February." Mark Twain*

*Bankruptcy is a particularly heinous word to investors and bankers, and 1982 has more than its share of casualties. The double whammy of historically high interest rates and a worldwide recession is causing managements of troubled companies to burn the midnight oil in their quest for a solution to their cash flow problems. The financial press continues to be laced with reports of numerous private and publicly-owned companies filing for Chapter 11 protection under the Bankruptcy Code.*

*In many industry sectors liquidity problems are facing companies that leveraged their balance sheets to acquire assets whose earning power depended on further price and/or volume gains. The oil and oil service sectors are particularly vulnerable in view of sliding volume and prices in the face of heavy debt burdens and large capital spending commitments and the deterioration in their financial ratios substantiates this.*

*Nevertheless, because of the indiscriminate sell-off of all oil issues during the past 22 months, we believe that some very compelling values have emerged in the oil group. With some discount for investor concern regarding oil industry corporate liquidity already reflected in the marketplace, on a positive note, investors should recognize that many companies in the oil sector have extremely strong balance sheets and undervalued oil reserves.*

*This report contains a computer screen of liquidity and financial data for a universe of 261 oil and oil service companies. We hope that these data, which should be considered merely as a starting point for further analysis, will be of value to our clients in evaluating those energy companies that may currently be part of their portfolios. Readers should note that the data contained herein have not been verified for accuracy.*

## INTRODUCTION

Why are so many oil companies facing financial difficulties today? More stringent lending terms by bankers are partly to blame (particularly in the wake of the recent celebrated failures of the Penn Square and Abilene National Banks, which were toppled by large loan losses to small energy companies). However, the principal cause of the current difficulties stems from the unexpected and unprecedented reversal in industry fundamentals. The state of euphoria that pervaded the energy markets and the Sun Belt and Rocky Mountain boom towns of Houston, Dallas/Fort Worth and Denver during the 1979-1981 period has given way to despair. The expectation of ever-increasing energy prices, new exploration successes (i.e., higher volumes) and expanding drilling activity caused many companies to spend well in excess of their internal cash generation to participate in the "black gold rush."

Permissive lending terms by many bankers allowed these companies to take on enormous debt loads relative to their assets and equity. Soft oil prices, increasing natural gas curtailments and onerous drilling commitments are the root of the oil producers' problems.

For oil service companies and drilling contractors, the free fall in North American drilling activity since the December 1981 peak has caused the fundamentals of the service sector to turn with a vengeance. The Hughes Tool rig count currently stands at 2,685 active units, off nearly 40% from the 4,424 active rigs a year ago. Excessive optimism on future growth in drilling activity caused the entire oil service group to overspend on new equipment and expansion. Market conditions throughout the industry have become increasingly competitive as managements continue to bid aggressively for a share of the shrinking market. (Meanwhile, idle equipment is causing cash flow hemorrhaging.) Given the new "old time religion" philosophy of oil companies--live within cash flow and try to retire some outstanding debt--the long-awaited rebound in drilling activity may be slow in materializing. Personnel layoffs, designed to reduce overhead, are commonplace throughout the industry from the major integrated oils to the small drilling contractors. The unemployment rate in previously booming Texas has shot up to a modern record of 8.5%. Indicative of the reversals suffered by oil operators, personal classified advertisements in Houston for expensive jewelry (Rolex watches, etc.) and automobiles (Cadillacs, Mercedes and BMWs) are up 50%-100% from this time a year ago.

Notwithstanding the recent sharp decline in both short- and long-term interest rates, it is our opinion that further troubles loom ahead in the energy sector this year. (See our August 5, 1982 report, "The Oil Industry.") A handful of oil and oil service companies (Saxon Oil, Dreco Energy, Nucorp Energy, et al) have already filed for Chapter 11 protection from creditors this year. Many of the small Denver "penny stocks" (Lewis Energy, Cram Exploration and American Resources Management) have been cited as experiencing cash flow problems as well. Meanwhile, Dome Petroleum, Canada's largest oil company, has undertaken an aggressive program to liquidate assets in order to trim its crushing C$7.6 billion debt burden.

On a much larger scale, Mexico is now experiencing extreme financial difficulties in the wake of a several-year multibillion-dollar development program to boost petroleum production from its large new discoveries. In many ways Mexico's past borrowing spree and excessive optimism for oil is similar to the 1979-1981 performance of the entire oil industry.

We have prepared the attached computer screen of liquidity and financial data for a universe of 261 oil and oil service companies. We hope that these data will be of value to our clients in evaluating any issues that may currently be included in their portfolios. On a positive note, it should be stressed that many oil issues have strong financial positions and significantly undervalued assets.

Considering the market carnage that has occurred in the energy sector during the past 22 months, one might question if our study is too late to be of investment decision-making value. We think not. Dr. Edwin Altman of New York University's Graduate School of Business Administration, widely regarded as the preeminent authority on bankruptcy prediction, wrote, "The average stock price decline among firms that went bankrupt was 45% from the time the Z-score model first predicted failure until 1 month prior to the failure date." While we have not provided a calculation of the Z-score for Oppenheimer's universe of oil companies in this report, clients with further interest in the results of this linear discriminant analysis approach should contact us.

In the remainder of this report we present some guidelines for interpreting the data contained in our screen. Some caveats are in order:

- We have not undertaken an analysis of the debt-to-true-asset value of these companies. It is well recognized on Wall Street that asset value analysis may e a more appropriate valuation approach for these types of issues due to "hidden assets" worth far more than stated book value. Banks traditionally lend on the basis of proven oil and gas reserve values of oil companies.

- We have not appraised their individual future cash generation capabilities. Investors should consider these data merely as a starting point for further analysis. Holdings which show troublesome financial ratios should be viewed in greater detail.

## OIL INDUSTRY LIQUIDY SCREEN

This report is presented in two sections. The first highlights a series of key liquidity and leverage ratios as well as current and prior 12-month price data. The second presents salient financial data on our oil universe. For most companies the data employed are as of December 31, 1982.

For comparative purposes we have segregated the companies into seven distinct industry segments: (1) Major Oil Companies; (2) Independent Producers; (3) Canadian Producers; (4) Pipelines and Gas Companies; (5) Drilling Companies; (6) Oil Well Equipment and Services; and (7) Refiners. Under each sector, companies are listed alphabetically.

## DEFINITIONS OF RATIOS

### Yellow Flag Ratios

The matrix presented should be viewed as a guide in the analysis of the financial health of individual issues. Perusal of this data shows that many oil companies display troublesome financial data. Admittedly, our screen is simplistic and could generate both Type I and Type II errors. Type I error would be defined as a prediction of financial health were the company is actually in serious financial difficulty. Type II error would be the prediction of financial problems where the company under analysis is not in danger of experiencing liquidity troubles.

Table I

Matrix of Yellow Flag Ratios

| | Interest Coverage | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Pretax | Pretax Cash Flow | Pretax Cash Flow With Cap. Spending | Sales/ Total Debt | Tot. Debt/ Mkt. Cap. | Debt Payback (in Years) | Interest Expense/ Aftertax Cash Flow | % Capital Spending/ Cash Flow | Common Equity/ Total Assets | Price/ Book |
| Range of Values | | | | | | | | | | |
| Observed | 129-0.06 | 127-0.35 | 15-(151) | 21-0.01 | 0.02-27 | 0.03-198 | 0.01-3.5 | 27%-N.M. | 0.83-0.09 | N.M.-0.23 |
| Yellow Flag Point | $<2.0$ | $<2.5$ | Any ( ) | $\leq 1.0$ | $>1.0$ | $>3.0$ | $\geq 1.0$ | $>100\%$ | $<0.40$ | -- |

( ) = Negative value.
N.M.= Not meaningful.

## COMMENTS AND CAVEATS ON THE DATA IN SECTION I

### Interest Coverage Ratios

Column 1. Earnings Before Interest and Taxes (EBIT) Coverage of Interest Expense
Column 2. Pretax Cash Flow Coverage
Column 3. Pretax Cash Flow Coverage of Interest and Capital Spending

$$\text{Pretax Income Coverage} = \frac{\text{Pretax Income + Gross Interest Expense (Pretax)}}{\text{Gross Interest Expense}}$$

$$\text{Pretax Cash Flow Coverage} = \frac{\text{Pretax Income + Gross Interest Expense + Depreciation Depletion and Other Non-cash Charges}}{\text{Gross Interest Expense}}$$

Pretax Cash Flow Coverage with Capital Spending = Same as 2 with Capital Spending subtracted from the Numerator

As a rule, the higher the value observed for these three ratios, the greater the conviction in the company's ability to service its debt. It is important to note that for companies with significant income from foreign oil and gas operations (e.g., Occidental, Phillips, Natomas, Belco and the internationals), aftertax cash flow coverage could be a more useful measure because these companies report large foreign oil and gas pretax earnings, but are taxed at an extremely high rate (85%-95%) on this income.

Ratios of 2.0 or less for column 1 or 2.5 or less for column 2 (or the observance of a negative value for pretax cash flow coverage, including capital spending) should be viewed as an indicator of possible liquidity problems. The coverage measure including capital spending should be interpreted as an indication of how much cash flow is left over after capital expenditure to service debt. If this ratio is less than 1.0 (or negative) the company, in effect, had to borrow to meet its interest obligations.

Importantly, in order to reduce the number of meaningless observations, we treated companies with deficits in a special manner. Instead of including the deficit in the numerator, we omitted it but added the figure to the denominator. This convention gives meaningful data, i.e., for companies with losses the coverage ratios are further reduced.

### Other Financial Ratios

Column 4. Sales/Total Debt

$$\text{Sales/Total Debt} = \frac{\text{Sales}}{\text{Long-term Debt + Short-term Bank Debt}}$$

A simplistic interpretation would indicate that if this ratio is 1.0 or less, a company could face difficulties in meeting its interest payments with sales equal to outstanding debt. In order to service debt at effective interest rates of 15%-20%, a company must have an operating profit margin of at least that order of magnitude.

Column 5. Debt/Market Capitalization

$$\text{Total Debt/Market Capitalization} = \frac{\text{Long-term Debt + Short-term Debt}}{\text{Shares Outstanding X Price}}$$

This leverage ratio looks at total debt to effective or perceived book value. As opposed to stated book value, market value indicates the value investors assign to the company's assets, net of debt. A value of 1.0 or higher indicates significant effective leverage. This approach is a test of the "efficient market" hypothesis.

Column 6. Total Debt Payback Period (years)

$$\begin{array}{l} \text{Total Debt Payback Period} \\ \text{(in years)} \end{array} = \frac{\text{Long-term Debt + Short-term Debt}}{\begin{array}{c} \text{Aftertax Cash Flow from Operations} \\ \text{(Net Income + Non-cash Charges)} \end{array}}$$

This measure shows how long it would take a company to fully retire its short- and long-term debt if every dollar of cash flow were directed toward debt repayment. As a rule, payback periods in excess of three years are grounds for further study.

Column 7. Interest Expense/Cash Flow

$$\text{Interest Expense/Cash Flow} = \frac{\text{Last 12-Month Gross Interest Expense}}{\text{Aftertax Cash Flow from Operations}}$$

This ratio indicates what portion of each cash flow dollar must be used to service outstanding debt. While interest expense is a pretax item and cash flow is aftertax cash flow from operations, one should recognize that many of the companies in our screen (primarily the independent producers) pay little, if any, income tax. In any event, it is fair to state that ratios approaching or exceeding 1.0 are noteworthy.

Column 8. Capital Spending/Cash Flow

$$\text{Capital Spending/Cash Flow} = \frac{\text{Capital Expenditure}}{\text{Aftertax Cash Flow from Operations}}$$

This percentage indicates to what extent the company's last 12-month capital spending was funded from internally-generated cash flow. An observation of higher than 100% indicates that some outside financing (debt or equity) was required to fund these outlays. It is interesting to note that virtually every company in our oil universe made capital expenditures in 1981 that were well in excess of internal cash flow, and in some instances, companies spent as much as 30 times internal cash flow last year. Caution should be used in interpreting negative values. A very small negative cash flow divided into a significant capital outlay will generate a potentially misleading statistic.

Column 9. Balance Sheet Leverage

$$\text{Common Equity/Total Assets} = \frac{\text{Common Shareholders' Equity (Excluding Preferred)}}{\text{Total Assets}}$$

This ratio of common equity to total assets is an indicator of leverage. An observation close to 1.0 (i.e., no debt) indicates a strong balance sheet. Observations below 0.40 (or NM, indicating a negative book value) suggest significant financial leverage.

## TROUBLED COMPANIES IN THE OIL SECTOR

Chapter 11 Filed

NU Corp. Energy
Drew Energy
Empire Oil and Gas
Bennett Petroleum
T.O.S. Industries
Amarex Oil
Beco International

Debt Restructuring Our Default on Long Convenance

Saxxon Oil
Wainoco Oil
Patrick Petroleum
TOSCO
Pengo Industries
Blocker Energy
MGF Oil
Anglo Energy

4/26/83

THE PENN SQUARE REPORT

OPPENHEIMER & CO.,INC.

SELECTED FINANCIAL RATIOS

| COMPANY | --PRICING-- HI-LO CURR. 12MN 4/26 | (1) PRETAX INCOME COVERAGE | (2) -INTEREST COVERAGE- PRETAX CASH FLOW COVERAGE | (3) -INTEREST COVERAGE- P/T CASH FLOW COVERAGE INCL. CAP. SPENDING | (4) SALES/ TOTAL DEBT | (5) TOTAL DEBT/ MKT.CAP. | (6) TOT. DEBT PAYBACK PERIOD (YEARS) | (7) INTEREST EXPENSE/ CASH FLOW | (8) % CAPITAL SPENDING/ CASH FLOW | (9) COMMON EQUITY/ TOTAL ASSETS |
|---|---|---|---|---|---|---|---|---|---|---|
| MAJOR OIL COMPANIES | | | | | | | | | | |
| AMERADA HESS CORP | 34- 16 26.1 | 3.32 | 5.34 | -.02 | 4.04 | 1.09 | 3.38 | .34 | 183.05 | .39 |
| ATLANTIC RICHFIELD CO | 50- 32 44.0 | 5.42 | 8.09 | 1.85 | 4.66 | .53 | 1.68 | .19 | 117.31 | .45 |
| BRITISH PETE LTD | 24- 18 24.3 | 4.07 | 6.15 | 1.01 | 4.49 | .96 | 2.87 | .33 | 169.57 | .33 |
| DU PONT E I DE NEMOURS & CO | 46- 30 45.5 | 3.85 | 5.75 | 2.41 | 5.39 | .58 | 2.24 | .36 | 119.13 | .44 |
| EXXON CORP | 34- 25 34.1 | 9.98 | 13.79 | 3.47 | 13.31 | .25 | .97 | .12 | 120.22 | .46 |
| GETTY OIL CO | 60- 43 67.0 | 17.71 | 29.23 | 12.12 | 9.18 | .24 | .67 | .06 | 95.67 | .51 |
| GULF OIL CORP | 36- 24 34.3 | 8.86 | 14.68 | 5.57 | 10.02 | .47 | 1.02 | .12 | 106.00 | .49 |
| KERR MCGEE CORP | 40- 23 32.5 | 3.08 | 4.61 | 1.28 | 3.41 | .61 | 2.27 | .36 | 118.62 | .44 |
| MOBIL CORP | 30- 20 29.5 | 4.77 | 6.73 | 1.95 | 8.44 | .59 | 2.25 | .29 | 137.09 | .40 |
| MURPHY OIL CORP | 28- 16 26.0 | 13.02 | 20.78 | 10.07 | 6.79 | .40 | .72 | .09 | 97.09 | .30 |
| OCCIDENTAL PETE CORP | 23- 17 20.6 | 4.82 | 6.28 | 3.99 | 3.03 | 3.05 | 8.02 | .54 | 124.31 | .17 |
| PENNZOIL CO | 41- 24 37.0 | 2.76 | 4.80 | .72 | 1.96 | .61 | 2.35 | .30 | 123.17 | .37 |
| PHILLIPS PETE CO | 37- 24 35.1 | 7.25 | 10.48 | 4.14 | 7.31 | .40 | 1.24 | .19 | 123.09 | .48 |
| ROYAL DUTCH PETE CO | 43- 29 42.3 | 5.97 | 7.36 | 3.19 | 5.15 | .80 | 2.43 | .29 | 122.34 | .39 |
| SHELL OIL CO | 46- 29 41.1 | 5.10 | 7.53 | 3.01 | 3.67 | .43 | 1.70 | .21 | 93.07 | .48 |
| SHELL TRANS & TRADING LTD | 32- 24 30.9 | 5.97 | 7.36 | 3.19 | 5.15 | .71 | 2.59 | .31 | 130.20 | .39 |
| STANDARD OIL CO CALIF | 39- 24 38.5 | 15.94 | 22.58 | 4.26 | 14.84 | .18 | .92 | .07 | 124.66 | .56 |
| STANDARD OIL CO IND | 50- 34 45.4 | 7.77 | 12.48 | 5.85 | 6.59 | .32 | 1.03 | .12 | 78.27 | .47 |
| STANDARD OIL CO OHIO | 47- 27 46.3 | 6.54 | 8.02 | 3.60 | 2.87 | .41 | 1.69 | .22 | 97.27 | .45 |
| SUN INC | 38- 27 37.9 | 3.45 | 6.07 | 1.63 | 6.56 | .53 | 1.53 | .25 | 110.65 | .43 |
| TEXACO INC | 35- 26 35.3 | 10.44 | 16.69 | 6.26 | 16.69 | .31 | .92 | .09 | 96.82 | .52 |
| UNITED STATES STL CORP | 25- 16 23.4 | 1.10 | 2.02 | .29 | 2.46 | 3.16 | N/M | N/M | 288.96 | .31 |

DATA IN $ MILLIONS EXCEPT FOR RATIOS AND PERCENTAGES.
N/M IS NOT MEANINGFUL.

4/26/83

THE PENN SQUARE REPORT

OPPENHEIMER & CO.,INC.

SELECTED FINANCIAL RATIOS

| | --PRICING-- | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | --INTEREST COVERAGE-- | | | | | | | | |
| COMPANY | HI-LO 12MN | CURR. 4/26 | PRETAX INCOME COVERAGE | PRETAX CASH FLOW COVERAGE | P/T CASH FLOW COVERAGE INCL. CAP. SPENDING | SALES/ TOTAL DEBT | TOTAL DEBT/ MKT.CAP. | TOT. DEBT PAYBACK PERIOD (YEARS) | INTEREST EXPENSE/ CASH FLOW | % CAPITAL SPENDING/ CASH FLOW | COMMON EQUITY/ TOTAL ASSETS |
| INDEPENDENTS | | | | | | | | | | | |
| ADOBE OIL & GAS CORP | 22- 11 | 17.1 | 3.12 | 4.50 | -1.52 | 1.56 | .45 | 2.48 | .35 | 213.34 | .40 |
| ALLIED CORP | 48- 29 | 47.0 | 7.39 | 10.52 | 6.22 | 7.48 | .36 | 1.26 | .17 | 80.12 | .32 |
| AMAREX INC | 14- 1 | 1.0 | 1.23 | 1.79 | -5.87 | .23 | 25.94 | 15.59 | 1.34 | 1024.55 | .13 |
| AMERICAN PAC INTL INC | 2- 1 | 1.1 | 1.31 | 1.86 | .34 | .62 | 1.13 | 5.76 | 1.19 | 181.56 | .17 |
| AMERICAN PUB ENERGY CO | 2- 2 | 1.6 | 8.71 | 9.90 | 8.15 | .94 | .81 | 3.55 | .16 | 27.48 | .46 |
| AMERICAN QUASAR PETE CO | 12- 5 | 6.4 | .74 | 1.36 | -.13 | .36 | 1.23 | N/M | N/M | 317.40 | .23 |
| AMERICAN RES MGMT CORP | 9- 1 | 1.5 | .69 | .75 | -1.48 | .05 | 5.10 | N/M | N/M | -901.51 | N/M |
| APACHE CORP | 16- 8 | 11.1 | 2.76 | 4.17 | -1.37 | .61 | .92 | 3.58 | .41 | 226.86 | .37 |
| ARAPAHO PETE INC | 4- 2 | 1.9 | .77 | 1.78 | -1.95 | .82 | 1.35 | N/M | N/M | 409.49 | .51 |
| ARGO PETE CORP | 9- 5 | 4.8 | 1.62 | 2.37 | -3.65 | .46 | 1.29 | 7.43 | .83 | 501.30 | .33 |
| ARGONAUT ENERGY CORP | 4- 1 | 1.6 | .88 | 1.80 | -1.72 | .77 | 1.60 | N/M | N/M | 430.11 | .39 |
| BARUCH FOSTER CORP | 10- 6 | 9.0 | 28.52 | 49.16 | 12.34 | 13.66 | .04 | .15 | .02 | 84.15 | .72 |
| BASIC EARTH SCIENCE SYS INC | 4- 1 | 3.4 | 1.51 | 10.55 | -25.49 | 5.09 | .02 | .59 | .10 | 377.30 | .93 |
| BEARD OIL CO | 8- 4 | 5.5 | 2.36 | 4.74 | -2.79 | 1.16 | .92 | 2.42 | .29 | 217.38 | .29 |
| BROCK EXPL CORP | 6- 2 | 4.0 | 1.33 | 2.39 | -1.21 | .82 | .67 | 5.94 | .79 | 283.96 | .20 |
| BURTON HAWKS INC | 4- 2 | 2.2 | 16.05 | 31.00 | -78.75 | N/M | .00 | .00 | .03 | 365.83 | .85 |
| CALLON PETE CO | 12- 4 | 11.0 | 1.38 | 2.24 | -5.23 | .30 | .55 | 8.19 | .73 | 548.01 | .27 |
| CAPITAL ENERGY CORP CALIF | 2- 0 | 1.6 | .15 | .43 | -.52 | .35 | .33 | N/M | N/M | -167.74 | .28 |
| CENTURY OIL & GAS CORP DEL | 4- 2 | 3.9 | 39.62 | 66.31 | -26.08 | 4.19 | .04 | .68 | .02 | 141.46 | .75 |
| CHAPARRAL RES INC | 8- 2 | 2.4 | 1.52 | 1.75 | -2.63 | .15 | .22 | 16.14 | 1.79 | 784.85 | .56 |
| CONSOLIDATED OIL & GAS INC | 10- 5 | 6.0 | .80 | 1.03 | -.10 | .30 | 2.40 | N/M | N/M | 599.02 | .14 |
| DAMSON OIL CORP | 9- 6 | 7.9 | 1.61 | 2.56 | -.30 | .54 | 2.10 | 5.53 | .76 | 218.21 | .26 |
| DIAMOND SHAMROCK CORP | 26- 17 | 23.3 | 3.19 | 5.25 | -.55 | 3.35 | .64 | 2.35 | .26 | 152.08 | .44 |
| DYCO PETE CORP | 21- 12 | 13.6 | 2.85 | 3.31 | 1.27 | .45 | 1.07 | 5.21 | .60 | 123.33 | .25 |
| ENERGY METHODS CORP | 3- 1 | 2.7 | 1.71 | 2.90 | -6.62 | .38 | .75 | 8.39 | .55 | 527.51 | .32 |
| ENERGY MINERALS CORP COLO | 5- 3 | 4.0 | 3.57 | 24.55 | -25.27 | 1.73 | .23 | .97 | .04 | 204.96 | .57 |
| ENERGY RESVS GROUP INC | 7- 3 | 3.3 | .52 | 1.84 | -.43 | .78 | 1.36 | N/M | N/M | 247.79 | .26 |
| ENERGY VENTURES INC | 11- 6 | 7.5 | 30.02 | 59.89 | -64.08 | N/M | .00 | .00 | .02 | 258.76 | .52 |
| EQUITY OIL CO | 11- 7 | 7.5 | N/M | N/M | N/M | N/M | .00 | .00 | .00 | 107.15 | .67 |
| FELMONT OIL CORP | 21- 10 | 18.6 | 9.22 | 15.39 | .15 | 4.54 | .08 | .43 | .09 | 131.86 | .64 |
| FOREST OIL CORP | 26- 15 | 24.4 | 1.40 | 2.54 | .49 | .47 | 2.04 | 4.98 | .71 | 146.09 | .18 |
| FREEPORT MCMORAN INC | 24- 12 | 22.3 | 2.13 | 4.92 | -2.77 | 1.48 | .33 | 2.12 | .26 | 201.14 | .44 |
| GALAXY OIL CO | 7- 1 | 1.6 | 1.04 | 2.09 | -8.18 | .33 | 3.25 | 10.84 | .93 | 955.69 | .36 |
| GENERAL HYDROCARBONS INC | 4- 1 | 1.6 | 1.87 | 2.85 | -38.80 | .39 | .36 | 18.77 | .54 | 2251.63 | .32 |
| GEORESOURCES INC | 4- 2 | 2.1 | 5.67 | 7.01 | -5.64 | 2.23 | .22 | 1.39 | .17 | 219.11 | .59 |

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4/26/83

THE PENN SQUARE REPORT

OPPENHEIMER & CO.,INC.

SELECTED FINANCIAL RATIOS

| | | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | INTEREST COVERAGE | | | | | | | | |
| COMPANY | --PRICING-- HI-LO 12MN | CURR. 4/26 | PRETAX INCOME COVERAGE | PRETAX CASH FLOW COVERAGE | P/T CASH FLOW COVERAGE INCL. CAP. SPENDING | SALES/ TOTAL DEBT | TOTAL DEBT/ MKT.CAP. | TOT. DEBT PAYBACK PERIOD (YEARS) | INTEREST EXPENSE/ CASH FLOW | % CAPITAL SPENDING/ CASH FLOW | COMMON EQUITY/ TOTAL ASSETS |
| GOLDEN OIL CO | 2- 1 | 1.7 | 1.78 | 4.62 | .44 | 1.39 | .17 | 1.64 | .28 | 118.67 | .38 |
| GOLDEN TRIANGLE RLTY & OIL I | 1- 0 | .9 | .01 | .35 | -.99 | .11 | .04 | N/M | N/M | -206.43 | .71 |
| GREENWOOD RES LTD | 2- 1 | 1.3 | 5.86 | 7.82 | -9.55 | .46 | .25 | 2.47 | .15 | 254.81 | .46 |
| GULF ENERGY CORP | 1- 0 | .3 | 2.20 | 3.73 | -.21 | 6.52 | .21 | 2.27 | .41 | 163.39 | .27 |
| HADSON PETE CORP | 14- 4 | 4.6 | 4.04 | 4.38 | -7.09 | .29 | .66 | 3.31 | .43 | 487.92 | .27 |
| HAMILTON BROS PETE CORP | 20- 9 | 11.9 | 3.62 | 5.52 | 1.12 | 1.96 | .51 | 1.88 | .29 | 128.52 | .52 |
| HARKEN OIL & GAS INC | 6- 1 | 2.5 | .14 | .70 | -1.49 | .54 | .70 | N/M | N/M | -1089.06 | .63 |
| HENDERSON PETE CORP | 2- 1 | 1.0 | .50 | 1.40 | -5.90 | .70 | .26 | N/M | N/M | 1034.33 | .46 |
| HERSHEY OIL CORP | 7- 4 | 6.6 | 60.10 | 127.38 | -145.55 | 14.52 | .01 | .15 | .01 | 274.83 | .75 |
| HOTEL INVS TR | 28- 21 | 23.6 | 2.67 | 2.67 | 2.67 | .36 | .59 | 5.47 | .60 | .00 | .57 |
| HOWELL PETE CORP | 22- 9 | 20.4 | N/M | N/M | N/M | 23.39 | .03 | .19 | N/M | 94.57 | .74 |
| INEXCO OIL CO | 17- 6 | 8.6 | 1.54 | 3.07 | -1.07 | .52 | 1.97 | 4.41 | .52 | 216.73 | .30 |
| INTERCONTINENTAL ENERGY CORP | 6- 2 | 3.1 | .21 | 1.05 | .45 | 1.32 | .48 | N/M | N/M | 1224.05 | .45 |
| JAYTEX OIL & GAS CO | 5- 1 | 1.5 | 1.16 | 3.69 | -11.91 | .40 | .40 | 3.62 | .37 | 580.61 | .21 |
| K R M PETE CORP | 9- 4 | 4.3 | 10.68 | 21.62 | -16.10 | N/M | .00 | .00 | .05 | 195.15 | .77 |
| KEDA OIL & GAS CO | 1- 0 | .7 | N/M | N/M | N/M | N/M | .00 | .00 | .00 | 289.01 | .94 |
| KIRBY EXPL CO | 17- 7 | 7.6 | 3.69 | 5.24 | -8.48 | 1.10 | .45 | 3.12 | .25 | 341.28 | .41 |
| LEAR PETE CORP | 19- 10 | 18.0 | 1.21 | 2.75 | -1.26 | .78 | 1.88 | 4.79 | .58 | 232.66 | .20 |
| LOUISIANA LD & EXPL CO | 32- 20 | 32.0 | 3.58 | 9.64 | -.38 | 3.23 | .30 | 1.07 | .13 | 128.65 | .50 |
| MAGIC CIRCLE ENERGY CORP | 7- 2 | 2.3 | 3.16 | 4.13 | -4.17 | 1.09 | 1.20 | 3.55 | .43 | 357.76 | .21 |
| MAY PETE INC | 18- 5 | 10.4 | 4.50 | 7.76 | -1.90 | 1.13 | .39 | 1.88 | .18 | 174.88 | .57 |
| MAYNARD OIL CO | 8- 4 | 6.0 | 4.14 | 11.99 | -3.26 | 1.93 | .60 | 1.09 | .10 | 152.21 | .38 |
| MCCORMICK OIL & GAS CO | 13- 6 | 7.8 | .25 | .64 | -.80 | .61 | .74 | N/M | N/M | 3064.23 | .27 |
| MCFARLAND ENERGY INC | 10- 6 | 9.4 | N/M | N/M | N/M | N/M | .00 | .00 | .00 | 139.27 | .70 |
| MESA PETE CO | 20- 10 | 12.4 | 3.00 | 4.28 | 1.05 | .50 | .91 | 2.98 | .38 | 123.75 | .25 |
| MID AMER PETE INC | 4- 2 | 2.1 | 6.58 | 8.31 | -.61 | 3.71 | .12 | 1.71 | .20 | 182.73 | .22 |
| MITCHELL ENERGY & DEV CORP | 22- 10 | 19.8 | 2.71 | 3.60 | -.57 | 1.33 | .85 | 3.80 | .51 | 212.82 | .23 |
| NATOMAS CO | 22- 13 | 15.8 | 2.20 | 5.35 | -.61 | 1.40 | 1.39 | 2.43 | .29 | 171.36 | .38 |
| NORRIS OIL CO | 7- 4 | 4.0 | 1.05 | 1.29 | -3.05 | .96 | .22 | 7.40 | 3.55 | 1022.77 | .69 |
| NORTH AMERN RTYS INC | 16- 8 | 14.3 | 27.79 | 52.59 | 4.58 | 18.93 | .06 | .25 | .02 | 116.45 | .56 |
| NUGGET OIL CORP | 2- 1 | 1.0 | 2.67 | 3.39 | -20.76 | .70 | 1.06 | 9.31 | .42 | 1008.54 | .40 |
| ORIGINALA PETE INC | 2- 1 | 1.3 | .34 | 1.07 | .27 | 1.10 | .58 | N/M | N/M | 1094.30 | .46 |
| OXOCO | 12- 6 | 11.0 | 1.79 | 2.52 | -4.94 | .38 | .94 | 6.08 | .71 | 531.33 | .22 |
| PARK OHIO INDS INC DEL | 18- 12 | 14.0 | 4.77 | 7.48 | 3.96 | 6.76 | .34 | 1.21 | .19 | 67.78 | .59 |
| PATTON OIL CO | 4- 2 | 2.5 | 1.92 | 3.41 | -4.56 | 1.22 | .50 | 2.76 | .44 | 346.58 | .45 |

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THE PENN SQUARE REPORT

OPPENHEIMER & CO.,INC.

SELECTED FINANCIAL RATIOS

| COMPANY | --PRICING-- HI-LO 12MN | CURR. 4/26 | (1) INTEREST COVERAGE: PRETAX INCOME COVERAGE | (2) PRETAX CASH FLOW COVERAGE | (3) P/T CASH FLOW COVERAGE INCL. CAP. SPENDING | (4) SALES/ TOTAL DEBT | (5) TOTAL DEBT/ MKT.CAP. | (6) TOT. DEBT PAYBACK PERIOD (YEARS) | (7) INTEREST EXPENSE/ CASH FLOW | (8) % CAPITAL SPENDING/ CASH FLOW | (9) COMMON EQUITY/ TOTAL ASSETS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PETRO LEWIS CORP | 13- 7 | 10.0 | 1.38 | 2.06 | -1.85 | .42 | 3.08 | 7.38 | 1.08 | 423.18 | .15 |
| PETROL INDS INC | 12- 5 | 6.1 | 27.83 | 30.55 | 17.05 | 7.65 | .03 | .38 | .04 | 56.87 | .03 |
| PETROLEUM DEV CORP | 4- 1 | 2.1 | 1.45 | 1.93 | -1.14 | .83 | 1.03 | 6.07 | .82 | 252.98 | .24 |
| POGO PRODUCING CO | 27- 17 | 24.3 | 2.84 | 5.48 | -1.37 | .63 | .75 | 2.51 | .27 | 183.71 | .32 |
| POLLOCK PETE INC | 1- 0 | .7 | .06 | .74 | -10.98 | .07 | .41 | N/M | N/M | -7563.30 | .51 |
| PREMIER RES LTD COLO | 3- 1 | 1.4 | .58 | 1.42 | -.53 | .65 | 3.17 | N/M | N/M | 379.67 | .12 |
| PRESIDIO OIL CO | 5- 3 | 4.6 | 2.73 | 6.02 | -3.23 | 1.61 | .17 | 1.39 | .21 | 195.63 | .68 |
| RANGER OIL LTD | 8- 4 | 7.5 | 7.19 | 9.76 | 6.97 | 1.67 | .27 | 1.81 | .23 | 64.34 | .25 |
| REGAL PETE LTD | 1- 1 | .6 | 136.30 | 184.00 | 13.60 | N/M | .00 | .00 | .01 | 124.84 | .68 |
| SABINE CORP | 43- 14 | 20.4 | 3.41 | 6.30 | 2.24 | 1.82 | .34 | 1.50 | .23 | 92.16 | .49 |
| SAXON OIL CO | 5- 1 | .9 | 1.11 | 1.51 | -4.77 | .27 | 5.19 | 14.65 | 2.24 | 1409.58 | .14 |
| SENECA OIL CO | 7- 2 | 2.8 | .62 | 1.12 | -1.29 | .32 | 3.13 | N/M | N/M | 1327.74 | .16 |
| SOUTHLAND RTY CO | 23- 14 | 17.6 | 2.04 | 3.30 | .95 | .90 | .56 | 4.41 | .56 | 132.55 | .15 |
| STATEX PETE INC | 12- 8 | 9.1 | N/M | N/M | N/M | 11.32 | .04 | .20 | N/M | 139.70 | .80 |
| SUPERIOR OIL CO | 38- 21 | 35.0 | 3.73 | 6.77 | .13 | 1.53 | .30 | 1.91 | .22 | 148.79 | .46 |
| TEXAS AMERN ENERGY CORP | 7- 3 | 3.8 | .88 | 1.74 | .17 | 3.00 | 3.26 | N/M | N/M | 193.15 | .18 |
| TEXAS AMERN RES INC | 1- 0 | .6 | .43 | .63 | -2.43 | .11 | .81 | N/M | N/M | -1817.51 | .17 |
| TEXAS GENL RES INC | 12- 1 | 1.5 | 6.23 | 6.83 | -12.58 | .58 | 7.41 | 5.43 | .25 | 493.92 | .21 |
| TEXAS INTL CO | 16- 5 | 6.0 | 1.34 | 2.37 | -.17 | .42 | 2.60 | 6.88 | .90 | 227.96 | .22 |
| TEXON ENERGY CORP | 13- 4 | 4.1 | 1.45 | 2.82 | 1.08 | .89 | .14 | 3.07 | .55 | 95.59 | .46 |
| TIPPERARY CORP | 10- 4 | 5.0 | .44 | .85 | -.68 | .66 | 3.05 | N/M | N/M | 1125.79 | .29 |
| TOWNER PETE CO | 9- 4 | 4.8 | 1.42 | 1.87 | -6.02 | 1.58 | 2.29 | 12.82 | 1.20 | 1038.19 | .22 |
| TRITON ENERGY CORP | 16- 8 | 11.9 | 2.70 | 4.38 | -2.99 | .77 | .73 | 4.29 | .39 | 288.12 | .35 |
| UNION PAC CORP | 56- 29 | 52.7 | 3.28 | 5.44 | .82 | 2.08 | .46 | 3.87 | .25 | 117.28 | .39 |
| UNIVERSAL RES CORP | 13- 5 | 6.4 | 1.76 | 3.81 | -5.84 | .66 | 1.57 | 3.25 | .37 | 356.82 | .45 |
| WAINOCO OIL CORP | 14- 4 | 5.4 | .65 | 1.19 | -1.57 | .32 | 2.34 | N/M | N/M | 916.94 | .30 |
| WICHITA INDS INC | 9- 4 | 5.9 | .41 | 1.11 | -.72 | 1.23 | .42 | N/M | N/M | 437.28 | .44 |
| WISER OIL CO DEL | 20- 14 | 18.1 | N/M | N/M | N/M | N/M | .00 | .00 | .00 | 94.23 | .83 |
| WOODS PETE CORP | 25- 17 | 23.4 | 13.79 | 22.63 | 5.92 | 3.97 | .08 | .43 | .06 | 99.14 | .56 |

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OPPENHEIMER & CO.,INC.

SELECTED FINANCIAL RATIOS

| | | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | --PRICING-- | | --INTEREST COVERAGE-- | | | | | | | | |
| COMPANY | HI-LO 12MM | CURR. 4/26 | PRETAX INCOME COVERAGE | PRETAX CASH FLOW COVERAGE | P/T CASH FLOW COVERAGE INCL. CAP. SPENDING | SALES/ TOTAL DEBT | TOTAL DEBT/ MKT.CAP. | TOT. DEBT PAYBACK PERIOD (YEARS) | INTEREST EXPENSE/ CASH FLOW | % CAPITAL SPENDING/ CASH FLOW | COMMON EQUITY/ TOTAL ASSETS |
| CANADIAN PRODUCERS | | | | | | | | | | | |
| BANISTER CONTL LTD | 9- 5 | 7.5 | .78 | 1.25 | .94 | 6.51 | .71 | 3.24 | .90 | 35.74 | .34 |
| BLUEWATER OIL & GAS LTD | 5- 3 | 3.9 | N/M | N/M | N/M | N/M | .00 | .00 | .00 | 94.49 | .76 |
| BOW VALLEY INDS LTD | 17- 11 | 16.5 | 1.62 | 2.31 | -2.94 | .75 | .92 | 6.29 | .77 | 401.78 | .16 |
| CANADIAN OCCIDENTAL PETE LTD | 14- 8 | 11.4 | 4.66 | 6.03 | 3.35 | 2.09 | .35 | 1.65 | .24 | 83.49 | .37 |
| DISCOVERY OIL LTD | 2- 1 | 1.0 | .72 | 1.83 | -10.01 | 1.55 | .43 | N/M | N/M | 1459.96 | .52 |
| DOME PETE LTD | 8- 2 | 3.5 | .08 | 1.20 | .33 | .43 | 6.31 | N/M | N/M | -1523.20 | .07 |
| GULF CDA LTD | 15- 10 | 13.1 | 4.38 | 5.96 | .33 | 5.56 | .23 | 2.24 | .30 | 165.90 | .45 |
| HUSKY OIL LTD | 9- 4 | 8.9 | 1.13 | 1.94 | -.56 | 1.40 | 1.27 | 6.85 | 1.09 | 273.66 | .23 |
| INTER CITY GAS CORP | 12- 6 | 9.9 | 1.49 | 1.85 | .12 | 1.70 | 2.11 | 11.26 | 1.74 | 301.17 | .21 |
| INTERPROVINCIAL PIPE LINE LT | 23- 13 | 22.9 | 5.26 | 6.48 | 6.18 | 1.07 | .47 | 2.08 | .31 | 9.00 | .35 |
| NORTH CDN OILS LTD | 17- 8 | 11.3 | 9.79 | 10.98 | 5.81 | .59 | .60 | 3.36 | .13 | 66.36 | .46 |
| NUMAC OIL & GAS LTD | 17- 9 | 14.8 | .46 | .73 | -1.56 | .23 | .39 | N/M | N/M | -673.62 | .34 |
| PAGE PETE LTD | 12- 3 | 4.5 | .69 | 1.07 | -3.17 | .23 | 6.79 | N/M | N/M | 7115.79 | .08 |
| SUNDANCE OIL CO | 12- 5 | 6.0 | .60 | .90 | -.23 | .25 | 2.87 | N/M | N/M | -5711.26 | N/M |
| TEXACO CDA INC | 29- 19 | 26.8 | 78.14 | 90.86 | 74.43 | 55.37 | .02 | .22 | .02 | 36.74 | .55 |
| WORLDWIDE ENERGY CORP | 9- 4 | 6.3 | .84 | 1.57 | -.86 | 1.19 | .81 | N/M | N/M | 365.29 | .32 |

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| COMPANY | --PRICING-- HI-LO CURR. 12MN 4/26 | (1) INTEREST COVERAGE PRETAX INCOME COVERAGE | (2) PRETAX CASH FLOW COVERAGE | (3) P/T CASH FLOW COVERAGE INCL. CAP. SPENDING | (4) SALES/ TOTAL DEBT | (5) TOTAL DEBT/ MKT.CAP. | (6) TOT. DEBT PAYBACK PERIOD (YEARS) | (7) INTEREST EXPENSE/ CASH FLOW | (8) % CAPITAL SPENDING/ CASH FLOW | (9) COMMON EQUITY/ TOTAL ASSETS |
|---|---|---|---|---|---|---|---|---|---|---|
| PIPELINES AND GAS | | | | | | | | | | |
| DORCHESTER GAS CORP | 18- 10 10.3 | 2.67 | 3.69 | .52 | 6.28 | 1.04 | 4.52 | .55 | 175.74 | .26 |
| ENTEX INC | 24- 11 22.1 | 2.75 | 3.73 | 1.18 | 4.29 | .59 | 3.16 | .47 | 119.29 | .28 |
| EQUITABLE GAS CO | 36- 19 25.6 | 4.96 | 5.69 | 3.34 | 2.10 | .97 | 3.75 | .34 | 78.15 | .39 |
| GULF ENERGY & DEV CORP | 10- 5 8.7 | 2.61 | 3.77 | -1.78 | 1.17 | 1.14 | 3.37 | .41 | 226.15 | .27 |
| NORTHWEST ENERGY CO | 20- 13 16.8 | 1.89 | 2.43 | .98 | 1.36 | 4.29 | 12.92 | 1.07 | 155.73 | .16 |
| ONEOK INC | 30- 24 24.3 | 3.64 | 4.72 | -.76 | 2.81 | 1.37 | 4.34 | .36 | 198.48 | .34 |
| PARGAS INC | 41- 14 40.6 | 7.18 | 10.70 | 7.89 | 7.99 | .20 | 1.33 | .15 | 41.04 | .53 |
| PEOPLES ENERGY CORP | 11- 7 8.8 | 3.81 | 5.06 | 3.02 | 4.29 | 1.35 | 3.89 | .35 | 72.30 | .28 |
| SOUTHERN UN CO | 20- 14 18.9 | 2.83 | 3.46 | 1.15 | 3.23 | 1.01 | 3.82 | .40 | 92.49 | .33 |
| TENNECO INC | 39- 23 37.0 | 2.28 | 3.38 | 1.14 | 2.61 | 1.14 | 3.04 | .51 | 113.43 | .31 |
| UGI CORP | 24- 18 19.4 | 3.19 | 4.37 | -.09 | 2.97 | 1.52 | 3.91 | .38 | 169.61 | .29 |
| WASHINGTON GAS LT CO | 31- 24 26.8 | 2.08 | 2.74 | 1.17 | 2.11 | 1.86 | 7.71 | .74 | 118.93 | .28 |

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| COMPANY | --PRICING-- HI-LO 12MM | CURR. 4/26 | (1) PRETAX INCOME COVERAGE | (2) PRETAX CASH FLOW COVERAGE | (3) P/T CASH FLOW COVERAGE INCL. CAP. SPENDING | (4) SALES/ TOTAL DEBT | (5) TOTAL DEBT/ MKT.CAP. | (6) TOT. DEBT PAYBACK PERIOD (YEARS) | (7) INTEREST EXPENSE/ CASH FLOW | (8) % CAPITAL SPENDING/ CASH FLOW | (9) COMMON EQUITY/ TOTAL ASSETS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ----INTEREST COVERAGE---- | | | | | | | | |
| DRILLING COMPANIES | | | | | | | | | | | |
| ANGLO ENERGY LTD | 11- 4 | 5.0 | .57 | 1.33 | -.44 | 1.94 | 3.20 | 5.45 | .75 | 231.34 | .35 |
| ASTRO DRILLING CO | 7- 1 | 2.1 | .55 | 1.22 | -.93 | 1.22 | 3.04 | N/M | N/M | 419.54 | .36 |
| ATWOOD OCEANICS INC | 27- 16 | 24.0 | 7.18 | 8.96 | 4.33 | 2.22 | .45 | 1.20 | .18 | 83.74 | .54 |
| BLOCKER ENERGY CORP | 8- 2 | 2.9 | 1.60 | 2.41 | -5.04 | .94 | 8.43 | 7.59 | .95 | 710.54 | .20 |
| BONRAY DRILLING CORP | 8- 3 | 3.1 | 7.92 | 10.25 | 2.64 | 3.45 | .72 | .78 | .15 | 112.50 | .60 |
| BROWN TOM INC | 16- 5 | 7.0 | 2.95 | 4.52 | -1.80 | 1.63 | .48 | 2.99 | .34 | 217.33 | .35 |
| BUTTES GAS & OIL CO | 12- 8 | 8.5 | 1.13 | 1.60 | -1.72 | .49 | 8.82 | N/M | N/M | 954.69 | .09 |
| CRAWFORD ENERGY INC | 6- 2 | 3.0 | 1.00 | 2.44 | -3.51 | 1.06 | 1.55 | 4.45 | .63 | 374.24 | .21 |
| DELTA DRILLING CO | 8- 4 | 5.1 | 4.04 | 6.31 | -1.11 | 1.94 | .98 | N/M | N/M | 366.78 | .44 |
| DRILLERS INC | 15- 3 | 4.4 | 5.65 | 7.78 | -16.14 | 1.10 | 1.91 | 2.47 | .17 | 406.51 | .46 |
| GLOBAL MARINE INC | 16- 7 | 8.9 | 2.07 | 2.90 | -2.69 | .67 | 2.48 | 4.39 | .55 | 305.68 | .35 |
| HELMERICH & PAYNE INC | 25- 14 | 19.8 | 7.86 | 12.57 | 6.05 | 2.55 | .27 | .86 | .11 | 70.47 | .59 |
| KANEB SVCS INC | 19- 12 | 15.4 | 2.53 | 3.83 | .84 | 1.51 | 1.08 | 3.16 | .37 | 111.86 | .36 |
| KENAI CORP | 13- 4 | 4.9 | 3.2[illegible] | 4.37 | -2.59 | 1.61 | 3.59 | 3.43 | .38 | 263.94 | .34 |
| MOF OIL CORP | 7- 1 | 1.7 | 1.65 | 2.67 | -5.77 | .65 | 6.37 | 5.60 | .67 | 562.62 | .29 |
| MIDLAND SOUTHWEST CORP | 7- 2 | 2.3 | 2.37 | 3.97 | -9.16 | 1.07 | 3.45 | 3.42 | .35 | 462.77 | .35 |
| MORAN ENERGY INC | 19- 7 | 13.1 | 2.20 | 4.46 | -1.90 | .83 | .86 | 3.42 | .33 | 210.93 | .40 |
| NICKLOS OIL & GAS CO | 11- 4 | 4.4 | .18 | .99 | -.74 | 1.47 | 1.00 | N/M | N/M | 402.46 | .60 |
| NOBLE AFFILIATES INC | 17- 8 | 14.8 | 8.00 | 14.47 | 3.60 | 3.05 | .20 | .75 | .09 | 99.78 | .55 |
| OCEAN DRILLING & EXPL CO | 26- 16 | 24.5 | 21.86 | 32.04 | 15.36 | 5.48 | .14 | .45 | .05 | 84.06 | .48 |
| PARKER DRILLING CO | 15- 7 | 9.0 | 3.41 | 4.88 | 1.80 | 1.66 | 1.43 | 2.45 | .34 | 10[illegible].95 | .41 |
| RATLIFF DRILLING & EXPL CO | 9- 4 | 4.8 | 1.54 | 3.66 | -3.17 | 1.20 | 2.21 | 3.21 | .34 | 235.07 | .34 |
| READING & BATES CORP | 18- 10 | 13.6 | 4.23 | 5.67 | -3.60 | 1.09 | 1.25 | 3.40 | .32 | 295.08 | .40 |
| RIO GRANDE DRILLING CO | 5- 2 | 2.4 | 2.38 | 3.27 | -.96 | 1.43 | 1.70 | 2.36 | .45 | 191.90 | .47 |
| ROWAN COS INC | 14- 7 | 12.4 | 13.61 | 16.28 | 4.05 | 4.56 | .15 | .55 | .09 | 116.10 | .64 |
| SAGE DRILLING INC | 12- 4 | 5.0 | 35.39 | 46.08 | -2.34 | 10.01 | .25 | .51 | .03 | 144.79 | .67 |
| SAGE ENERGY CO | 11- 6 | 8.6 | 9.22 | 13.51 | .34 | 2.47 | .28 | .77 | .09 | 114.03 | .50 |
| SEDCO INC | 35- 23 | 33.3 | 10.11 | 11.26 | 8.72 | 1.77 | .40 | .93 | .16 | 39.46 | .39 |
| SOUTH TEX DRILLING & EXPL IN | 5- 1 | 3.5 | 5.18 | 7.10 | -20.98 | .66 | 1.73 | 3.98 | .18 | 506.00 | .39 |
| TRANSCONTINENTAL ENERGY CORP | 10- 4 | 4.5 | 3.03 | 4.74 | .52 | 1.67 | 2.23 | 2.26 | .30 | 128.36 | .37 |
| TUCKER DRILLING INC | 13- 8 | 8.9 | 37.59 | 56.11 | 5.62 | 20.81 | .09 | .21 | .02 | 121.28 | .66 |
| UNIT DRILLING & EXPL CO | 12- 4 | 6.1 | 6.74 | 9.30 | -3.93 | 1.64 | 1.05 | 1.59 | .16 | 208.80 | .46 |
| VERNA CORP | 7- 2 | 2.0 | .58 | 2.28 | -.51 | 2.13 | 3.88 | 2.33 | .33 | 155.70 | .31 |
| WESTBURNE INTL INDS LTD | 14- 7 | 12.9 | 1.77 | 2.35 | 1.22 | 4.83 | 1.62 | 7.15 | 1.17 | 132.35 | .34 |
| ZAPATA CORP | 22- 12 | 16.6 | 4.30 | 5.28 | 1.87 | 1.04 | 1.62 | 3.47 | .36 | 123.25 | .34 |

DATA IN $ MILLIONS EXCEPT FOR RATIOS AND PERCENTAGES.
N/M IS NOT MEANINGFUL.

4/26/83

# THE PENN SQUARE REPORT

## OPPENHEIMER & CO.,INC.

## SELECTED FINANCIAL RATIOS

| COMPANY | --PRICING-- HI-LO 12MM | CURR. 4/26 | (1) INTEREST COVERAGE: PRETAX INCOME COVERAGE | (2) INTEREST COVERAGE: PRETAX CASH FLOW COVERAGE | (3) INTEREST COVERAGE: P/T CASH FLOW COVERAGE INCL. CAP. SPENDING | (4) SALES/ TOTAL DEBT | (5) TOTAL DEBT/ MKT.CAP. | (6) TOT. DEBT PAYBACK PERIOD (YEARS) | (7) INTEREST EXPENSE/ CASH FLOW | (8) % CAPITAL SPENDING/ CASH FLOW | (9) COMMON EQUITY/ TOTAL ASSETS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **OIL WELL & EQUIPMENT SERVICES** | | | | | | | | | | | |
| BAKER INTL CORP | 34- 16 | 18.1 | 6.61 | 8.12 | 2.02 | 3.91 | .51 | 1.80 | .21 | 125.55 | .48 |
| BIG THREE INDS INC | 28- 15 | 21.1 | 7.66 | 10.54 | 3.20 | 3.45 | .25 | 1.48 | .15 | 107.89 | .58 |
| BOLT TECHNOLOGY CORP | 21- 12 | 13.6 | 252.29 | 280.06 | 182.77 | 161.02 | .00 | .02 | .01 | 54.81 | .84 |
| BRALORNE RES LTD | 7- 4 | 4.1 | .79 | 1.47 | .28 | 1.28 | 1.74 | N/M | N/M | 181.80 | .25 |
| CAMCO INC | 17- 8 | 15.4 | 8.02 | 9.46 | 7.19 | 6.35 | .26 | 1.19 | .17 | 42.22 | .55 |
| CAMERON IRON WKS INC | 31- 16 | 19.3 | 5.19 | 6.13 | 2.33 | 2.81 | .70 | 1.98 | .27 | 104.54 | .44 |
| CRUTCHER RES CORP | 15- 5 | 6.8 | 4.15 | 5.75 | -.07 | 2.15 | 1.84 | 2.76 | .27 | 155.25 | .33 |
| DORCHESTER GAS CORP | 18- 10 | 10.3 | 2.67 | 3.69 | .52 | 6.28 | 1.04 | 4.52 | .55 | 175.74 | .26 |
| DRESSER INDS INC | 24- 12 | 19.0 | 5.08 | 8.31 | 2.16 | 7.63 | .36 | 1.50 | .16 | 100.41 | .61 |
| EDISON SAULT ELEC CO | 13- 9 | 12.0 | 2.98 | 4.09 | .44 | 1.60 | 1.62 | 4.77 | .42 | 153.45 | .24 |
| ENTERRA CORP | 35- 15 | 17.3 | 23.25 | 30.50 | 5.75 | 2.67 | .61 | 1.19 | .05 | 119.31 | .47 |
| GALVESTON HOUSTON CO | 37- 10 | 10.9 | 8.41 | 6.45 | 1.42 | 2.29 | 1.57 | 3.07 | .27 | 137.57 | .40 |
| GEARHART INDS INC | 21- 10 | 20.3 | 5.23 | 7.63 | .05 | 3.18 | .35 | 1.77 | .20 | 152.85 | .50 |
| HALLIBURTON CO | 40- 21 | 33.9 | 7.67 | 10.63 | 6.68 | 9.43 | .19 | .89 | .14 | 56.54 | .62 |
| HUGHES TOOL CO | 29- 14 | 18.1 | 3.28 | 4.52 | 1.02 | 2.14 | .74 | 2.89 | .34 | 120.58 | .53 |
| MARK PRODS INC | 6- 2 | 3.1 | .50 | 2.06 | .91 | 3.60 | .45 | N/M | N/M | 77.81 | .61 |
| NEWPARK RES INC | 12- 5 | 5.9 | 5.33 | 6.71 | .57 | 3.87 | .90 | 1.97 | .26 | 157.70 | .46 |
| NL INDS INC | 28- 14 | 16.5 | 4.76 | 6.32 | 2.36 | 3.81 | .57 | 1.87 | .25 | 98.82 | .50 |
| NUCORP ENERGY INC | 2- 0 | .4 | 1.16 | 1.83 | -2.53 | .86 | 66.51 | 15.30 | 1.43 | 622.47 | .16 |
| OCEANEERING INTL INC | 18- 10 | 11.8 | N/M | N/M | N/M | 106.97 | .01 | .06 | N/M | 74.52 | .60 |
| OFFSHORE LOGISTICS INC | 16- 10 | 15.3 | 1.49 | 2.28 | 1.02 | 1.09 | 3.85 | 6.06 | .74 | 93.18 | .23 |
| PENN CENT CORP | 34- 20 | 29.6 | 3.97 | 5.23 | 3.27 | 6.17 | .58 | 2.14 | .36 | 70.09 | .47 |
| PETROLANE INC | 18- 11 | 13.3 | 6.90 | 9.92 | 4.00 | 8.21 | .35 | 1.33 | .14 | 83.66 | .49 |
| PETROLEUM EQUIP TOOLS CO | 18- 6 | 8.4 | 3.38 | 7.52 | .01 | 2.53 | .61 | 1.34 | .16 | 123.04 | .56 |
| PETROLITE CORP | 34- 20 | 28.1 | 32.24 | 40.19 | 24.60 | 23.51 | .04 | .31 | .04 | 58.14 | .71 |
| PYRAMID OIL CO | 6- 2 | 4.3 | 13.85 | 19.50 | 2.68 | 22.47 | .03 | .22 | .07 | 110.12 | .77 |
| SCHLUMBERGER LTD | 52- 30 | 43.5 | 16.43 | 21.43 | 12.05 | 6.20 | .08 | .50 | .06 | 56.64 | .67 |
| SEIS PROS INC | 9- 4 | 7.0 | 11.39 | 14.90 | 1.40 | 4.50 | .37 | .97 | .10 | 138.06 | .44 |
| SEISCOM DELTA INC | 10- 3 | 5.1 | .69 | 1.40 | .33 | 2.00 | 4.12 | N/M | N/M | 1[illegible].32 | .29 |
| SERVICE FRACTURING CO | 11- 4 | 6.4 | 27.59 | 37.98 | -7.78 | 12.09 | .11 | .35 | .04 | 161.31 | .78 |
| SMITH INTL INC | 34- 18 | 23.3 | 6.74 | 9.08 | 2.48 | 3.78 | .54 | 2.08 | .17 | 111.87 | .57 |
| TIDEWATER INC | 29- 16 | 24.3 | 7.60 | 10.26 | 2.04 | 2.44 | .48 | 1.62 | .15 | 122.72 | .46 |
| TRICO INDS INC | 12- 6 | 8.0 | 3.17 | 4.29 | -.00 | 3.40 | .50 | 3.72 | .40 | 170.12 | .54 |
| WEATHERFORD INTL INC | 20- 6 | 9.4 | 9.04 | 11.63 | 4.69 | 4.62 | .61 | 1.34 | .13 | 90.71 | .51 |
| WESTERN CO NORTH AMER | 14- 6 | 7.1 | 1.79 | 2.68 | -.01 | 1.02 | 2.14 | 4.87 | .66 | 177.06 | .30 |

DATA IN $ MILLIONS EXCEPT FOR RATIOS AND PERCENTAGES.
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4/26/83

THE FENN SQUARE REPORT

OPPENHEIMER & CO., INC.

SELECTED FINANCIAL RATIOS

| COMPANY | --PRICING-- HI-LO 12MN | CURR. 4/26 | (1) INTEREST COVERAGE PRETAX INCOME COVERAGE | (2) PRETAX CASH FLOW COVERAGE | (3) P/T CASH FLOW COVERAGE INCL. CAP. SPENDING | (4) SALES/ TOTAL DEBT | (5) TOTAL DEBT/ MKT.CAP. | (6) TOT. DEBT PAYBACK PERIOD (YEARS) | (7) INTEREST EXPENSE/ CASH FLOW | (8) % CAPITAL SPENDING/ CASH FLOW | (9) COMMON EQUITY/ TOTAL ASSETS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| XOIL ENERGY RES INC | 8- 2 | 3.0 | .09 | .21 | .09 | .54 | .59 | N/M | N/M | -20.41 | .13 |
| YANKEE OIL & GAS INC | 18- 5 | 17.1 | 5.75 | 6.67 | -8.23 | 2.49 | .24 | 3.75 | .27 | 395.26 | .34 |
| REFINERS | | | | | | | | | | | |
| AMERICAN PETROFINA INC | 63- 51 | 53.0 | 5.30 | 10.49 | 2.85 | 8.56 | .47 | 1.67 | .13 | 97.10 | .48 |
| ASAMERA INC | 26- 6 | 21.1 | 1.10 | 5.42 | -4.82 | 5.41 | .55 | 1.99 | .21 | 216.45 | .29 |
| ASHLAND OIL INC | 35- 22 | 31.1 | 4.31 | 6.27 | .90 | 10.82 | .99 | 2.31 | .25 | 133.98 | .25 |
| CHARTER CO | 16- 7 | 11.5 | 2.53 | 3.02 | 2.44 | 9.66 | 1.66 | 5.88 | 1.01 | 58.84 | .32 |
| COASTAL CORP | 27- 14 | 20.1 | 1.74 | 2.72 | .02 | 4.21 | 3.16 | 6.47 | .71 | 190.62 | .16 |
| COMMONWEALTH OIL REFNG INC | 1- 0 | .4 | .14 | .67 | .66 | 5.21 | 21.70 | N/M | N/M | -7.01 | N/M |
| CROWN CENT PETE CORP | 20- 13 | 18.5 | 1.38 | 5.07 | -.44 | 15.53 | .99 | 1.94 | .24 | 131.42 | .30 |
| CRYSTAL OIL CO | 19- 10 | 16.5 | 1.03 | 2.29 | -2.23 | 1.27 | .72 | 5.41 | .77 | 349.51 | .17 |
| HOLLY CORP | 12- 6 | 10.3 | 23.50 | 38.10 | 7.50 | 97.93 | .07 | .26 | .03 | 105.79 | .38 |
| HOWELL CORP | 13- 7 | 12.1 | 6.26 | 11.57 | 1.81 | 15.68 | .24 | 1.02 | .16 | 154.18 | .40 |
| MARION CORP | 5- 1 | 1.7 | .36 | .70 | -.08 | 5.27 | 3.82 | N/M | N/M | 1992.59 | .29 |
| NEENAH OIL INC | 9- 5 | 6.3 | 1.05 | 1.85 | -.22 | 10.36 | 1.84 | 6.37 | 1.16 | 240.42 | .25 |
| PAULEY PETE INC | 9- 4 | 6.6 | .43 | 1.15 | .33 | 3.26 | 3.25 | N/M | N/M | 489.23 | .12 |
| QUAKER ST OIL REFNG CORP | 20- 10 | 18.8 | 6.69 | 9.49 | 5.42 | 10.18 | .22 | 1.25 | .17 | 68.65 | .51 |
| TESORO PETE CORP | 24- 14 | 15.5 | 38.96 | 53.51 | 23.09 | 27.22 | .42 | .97 | .03 | 95.42 | .45 |
| TOMLINSON OIL INC | 4- 1 | 1.4 | .50 | .85 | .36 | 2.99 | 6.88 | N/M | N/M | -88.82 | .07 |
| TOSCO CORP | 19- 9 | 9.4 | 4.15 | 4.62 | 1.51 | 6.37 | 3.15 | 3.43 | .35 | 109.86 | .23 |
| TOTAL PETE NORTH AMER LTD | 13- 7 | 11.6 | 1.33 | 2.52 | 1.00 | 5.58 | 1.98 | 5.04 | .70 | 106.70 | .16 |

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THE PENN SQUARE REPORT

OPPENHEIMER & CO., INC.

SELECTED FINANCIAL DATA

| COMPANY | DATA AS OF | PRICE 4/26 | MARKET CAPIT. | STATED BOOK VALUE | PRICE/ BOOK VALUE | SALES | PRETAX INCOME | NET INCOME | P/E RATIO | INTEREST EXPENSE | DEPREC. DEPL.& AMORT. | CAPITAL EXPEND. | LONG TERM DEBT | SHORT TERM DEBT |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| MAJOR OIL COMPANIES | | | | | | | | | | | | | | |
| AMERADA HESS CORP | 12/81 | 26.1 | 2139.8 | 2490.3 | .86 | 9396.2 | 545.6 | 212.6 | 10.07 | 235.1 | 476.0 | 1260.5 | 1521.7 | 806.4 |
| ATLANTIC RICHFIELD CO | 12/82 | 44.0 | 10814.8 | 9830.1 | 1.10 | 26462.2 | 2798.1 | 1676.1 | 6.45 | 633.3 | 1693.8 | 3953.2 | 5071.6 | 606.3 |
| BRITISH PETE LTD | 12/82 | 24.3 | 11013.1 | 13988.0 | .79 | 47524.0 | 3734.0 | 1153.0 | 9.55 | 1216.0 | 2531.0 | 6247.0 | 6224.0 | 4364.0 |
| DU PONT E I DE NEMOURS | 12/82 | 45.5 | 10752.0 | 10613.0 | 1.01 | 33331.0 | 2806.0 | 894.0 | 12.03 | 984.0 | 1872.0 | 3295.0 | 5868.0 | 319.0 |
| EXXON CORP | 12/82 | 34.1 | 29666.5 | 28440.2 | 1.04 | 97172.8 | 7874.6 | 4185.9 | 7.09 | 876.6 | 3333.5 | 9039.9 | 4555.6 | 2742.7 |
| GETTY OIL CO | 12/82 | 67.0 | 5421.8 | 5100.4 | 1.06 | 11970.7 | 1816.7 | 491.4 | 7.84 | 188.7 | 1252.5 | 1860.0 | 1260.0 | 44.5 |
| GULF OIL CORP | 12/82 | 34.3 | 6004.7 | 9914.0 | .61 | 28427.0 | 2548.5 | 900.0 | 6.67 | 324.0 | 1885.0 | 2952.0 | 2214.0 | 624.0 |
| KERR MCGEE CORP | 12/82 | 32.5 | 1715.1 | 1672.4 | 1.03 | 3777.2 | 341.2 | 209.8 | 8.18 | 164.1 | 251.4 | 547.0 | 895.0 | 151.4 |
| MOBIL CORP | 12/82 | 29.5 | 12093.1 | 14742.0 | .82 | 59946.0 | 3405.0 | 1380.0 | 8.76 | 903.0 | 1772.0 | 4321.0 | 4717.0 | 2365.0 |
| MURPHY OIL CORP | 12/82 | 26.0 | 956.8 | 901.7 | 1.06 | 2402.5 | 379.9 | 157.8 | 6.67 | 48.3 | 374.5 | 516.8 | 293.4 | 89.8 |
| OCCIDENTAL PETE CORP | 12/82 | 20.6 | 1965.0 | 2636.3 | .75 | 18212.2 | 1550.0 | 155.6 | 12.63 | 406.1 | 593.0 | 930.6 | 4329.9 | 1670.9 |
| PENNZOIL CO | 12/82 | 37.0 | 1898.2 | 1180.0 | 1.61 | 2268.5 | 260.9 | 188.7 | 10.06 | 148.6 | 303.2 | 606.0 | 1149.9 | 5.7 |
| PHILLIPS PETE CO | 12/82 | 35.1 | 5370.3 | 5773.0 | .93 | 15698.0 | 2100.0 | 646.0 | 8.33 | 336.0 | 1086.0 | 2132.0 | 1955.0 | 193.0 |
| ROYAL DUTCH PETE CO | 12/81 | 42.3 | 11324.6 | 15166.2 | .75 | 46530.0 | 5417.0 | 2197.4 | 5.15 | 1091.0 | 1517.0 | 4544.0 | 6323.0 | 2714.0 |
| SHELL OIL CO | 12/82 | 41.1 | 12707.4 | 10290.0 | 1.23 | 20062.0 | 2715.0 | 1605.0 | 7.92 | 663.0 | 1615.0 | 2997.0 | 4977.0 | 491.0 |
| SHELL TRANS & TRADING L | 12/81 | 30.9 | 8527.9 | 10090.7 | .85 | 31020.0 | 3612.0 | 1315.4 | 6.48 | 727.0 | 1011.0 | 3029.0 | 4216.0 | 1807.0 |
| STANDARD OIL CO CALIF | 12/82 | 38.5 | 13171.2 | 13246.0 | .99 | 34362.0 | 2554.0 | 1377.0 | 9.57 | 171.0 | 1137.0 | 3134.0 | 1934.0 | 382.0 |
| STANDARD OIL CO IND | 12/82 | 45.4 | 13276.0 | 11426.5 | 1.16 | 28073.2 | 3292.0 | 1826.1 | 7.27 | 486.1 | 2280.6 | 3220.7 | 3963.5 | 293.3 |
| STANDARD OIL CO OHIO | 12/82 | 46.3 | 11373.8 | 7221.0 | 1.58 | 13529.0 | 3397.0 | 1879.0 | 6.05 | 613.0 | 905.0 | 2708.0 | 4185.0 | 533.0 |
| SUN INC | 12/82 | 37.9 | 4495.8 | 5191.0 | .87 | 15519.0 | 944.0 | 537.0 | 8.37 | 386.0 | 1012.0 | 1714.0 | 2187.0 | 180.0 |
| TEXACO INC | 12/82 | 35.3 | 9166.8 | 14226.0 | .64 | 46986.0 | 2672.0 | 1281.0 | 7.16 | 283.0 | 1768.0 | 2952.0 | 2427.0 | 389.0 |
| UNITED STATES STL CORP | 12/82 | 23.4 | 2371.1 | 5933.0 | .40 | 18375.0 | 113.0 | -361.0 | -6.57 | 1118.0 | 1031.0 | 1936.0 | 6843.0 | 640.0 |

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4/26/83

THE PENN SQUARE REPORT

OPPENHEIMER & CO.,INC.

SELECTED FINANCIAL DATA

| COMPANY | DATA AS OF | PRICE 4/26 | MARKET CAPIT. | STATED BOOK VALUE | PRICE/ BOOK VALUE | SALES | PRETAX INCOME | NET INCOME | P/E RATIO | INTEREST EXPENSE | DEPREC. DEPL.& AMORT. | CAPITAL EXPEND. | LONG TERM DEBT | SHORT TERM DEBT |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| INDEPENDENTS | | | | | | | | | | | | | | |
| ADOBE OIL & GAS CORP | 12/81 | 17.1 | 263.4 | 145.7 | 1.81 | 184.5 | 35.9 | 24.4 | 10.79 | 16.9 | 23.3 | 101.8 | 114.7 | 3.7 |
| ALLIED CORP | 12/82 | 47.0 | 2263.4 | 2013.0 | 1.12 | 6167.0 | 779.0 | 272.0 | 8.32 | 122.0 | 382.0 | 524.0 | 700.0 | 125.0 |
| AMAREX INC | 4/82 | 1.0 | 8.8 | 50.5 | .17 | 52.9 | 4.5 | 3.7 | 2.37 | 19.5 | 16.9 | 149.5 | 227.4 | .0 |
| AMERICAN PAC INTL INC | 12/81 | 1.1 | 11.8 | 3.5 | 3.38 | 8.3 | .9 | .8 | 14.73 | 2.8 | 1.5 | 4.2 | 11.7 | 1.7 |
| AMERICAN PUB ENERGY CO | 12/81 | 1.6 | 6.0 | 10.5 | .57 | 4.6 | 1.7 | 1.1 | 5.38 | .2 | .3 | .4 | 1.6 | 3.3 |
| AMERICAN QUASAR PETE CO | 12/82 | 6.4 | 123.2 | 57.7 | 2.14 | 54.1 | -8.1 | -4.8 | -25.87 | 23.3 | 19.6 | 47.2 | 121.0 | 30.4 |
| AMERICAN RES MGMT CORP | 12/81 | 1.5 | 11.1 | -.3 | -33.54 | 2.8 | -3.9 | -3.9 | -2.85 | 8.6 | .8 | 28.0 | 3.6 | 53.0 |
| APACHE CORP | 12/82 | 11.1 | 243.6 | 209.7 | 1.16 | 135.1 | 44.9 | 26.3 | 9.27 | 25.5 | 36.1 | 141.5 | 211.0 | 12.2 |
| ARAPAHO PETE INC | 5/82 | 1.9 | 6.7 | 13.9 | .48 | 7.4 | -.4 | -.1 | -44.79 | 1.2 | 1.6 | 5.9 | 9.0 | .0 |
| ARGO PETE CORP | 12/81 | 4.8 | 36.6 | 30.7 | 1.19 | 22.0 | 3.3 | 2.4 | 15.57 | 5.3 | 4.0 | 32.0 | 46.8 | .6 |
| ARGONAUT ENERGY CORP | 3/82 | 1.6 | 6.1 | 8.1 | .75 | 7.5 | -.2 | -.2 | -32.37 | 1.6 | 1.7 | 6.5 | 9.4 | .2 |
| BARUCH FOSTER CORP | 12/81 | 9.0 | 22.5 | 9.4 | 2.40 | 12.5 | 3.9 | 3.2 | 6.95 | .1 | 2.9 | 5.2 | .8 | .2 |
| BASIC EARTH SCIENCE SYS | 3/82 | 3.4 | 39.4 | 18.0 | 2.19 | 3.6 | .1 | .1 | 615.12 | .1 | 1.1 | 4.5 | .7 | .0 |
| BEARD OIL CO | 12/81 | 5.5 | 33.8 | 16.8 | 2.02 | 36.1 | 4.7 | 3.7 | 9.12 | 3.4 | 8.2 | 25.9 | 28.7 | 2.6 |
| BROCK EXPL CORP | 3/82 | 4.0 | 15.6 | 4.9 | 3.18 | 8.6 | .4 | .3 | 54.39 | 1.4 | 1.5 | 5.0 | 6.7 | 3.8 |
| BURTON HAWKS INC | 12/81 | 2.2 | 21.7 | 10.6 | 2.05 | 2.7 | .6 | .6 | 36.11 | .0 | .6 | 4.4 | .0 | .0 |
| CALLON PETE CO | 5/82 | 11.0 | 84.6 | 23.1 | 3.66 | 14.2 | 1.6 | 2.1 | 40.76 | 4.2 | 3.6 | 31.3 | 45.9 | .9 |
| CAPITAL ENERGY CORP CAL | 12/81 | 1.6 | 15.2 | 3.0 | 5.14 | 1.7 | -2.1 | -2.1 | -7.09 | .4 | .7 | 2.4 | 2.6 | 2.4 |
| CENTURY OIL & GAS CORP | 12/81 | 3.9 | 15.7 | 2.9 | 5.40 | 2.4 | .5 | .5 | 31.33 | .0 | .3 | 1.2 | .0 | .6 |
| CHAPARRAL RES INC | 11/82 | 2.4 | 24.2 | 8.8 | 2.[illegible] | .8 | .3 | .2 | 126.72 | .6 | .1 | 2.6 | 5.3 | .0 |
| CONSOLIDATED OIL & GAS | 11/82 | 6.0 | 54.5 | 24.0 | 2.2[illegible] | 39.2 | -5.0 | -1.0 | -53.19 | 19.9 | 5.7 | 28.1 | 124.2 | 6.5 |
| DAMSON OIL CORP | 9/82 | 7.9 | 58.4 | 71.5 | .[illegible] | 66.8 | 10.4 | 6.1 | 9.51 | 17.0 | 16.1 | 48.4 | 99.8 | 22.9 |
| DIAMOND SHAMROCK CORP | 12/82 | 23.3 | 1475.3 | 1407.2 | 1.05 | 3177.4 | 231.4 | 185.1 | 7.97 | 105.7 | 217.8 | 612.7 | 925.1 | 22.4 |
| DYCO PETE CORP | 12/81 | 13.6 | 101.5 | 43.5 | 2.33 | 49.2 | 23.2 | 15.0 | 6.77 | 12.5 | 5.8 | 25.6 | 63.1 | 45.0 |
| ENERGY METHODS CORP | 9/82 | 2.7 | 14.4 | 6.0 | 2.40 | 4.1 | .5 | .4 | 33.37 | .7 | .8 | 6.8 | 10.1 | .7 |
| ENERGY MINERALS CORP CO | 12/81 | 4.0 | 21.6 | 20.3 | 1.07 | 8.7 | .5 | .7 | 30.42 | .2 | 4.5 | 10.7 | 5.0 | .0 |
| ENERGY RESVS GROUP INC | 12/81 | 3.3 | 162.7 | 91.5 | 1.78 | 173.6 | -26.7 | -22.6 | -7.20 | 28.7 | 73.5 | 126.0 | 220.9 | .5 |
| ENERGY VENTURES INC | 12/01 | 7.5 | 20.9 | 37.3 | .56 | 8.7 | 5.2 | 3.2 | 6.52 | .2 | 5.3 | 22.1 | .0 | .0 |
| EQUITY OIL CO | 12/81 | 7.5 | 88.3 | 31.5 | 2.80 | 23.8 | 7.8 | 5.6 | 15.85 | .0 | 2.5 | 8.6 | .0 | .0 |
| FELMONT OIL CORP | 12/81 | 18.6 | 193.7 | 91.5 | 2.12 | 70.1 | 25.6 | 16.7 | 11.57 | 3.1 | 19.2 | 47.4 | 15.1 | .3 |
| FOREST OIL CORP | 12/82 | 24.4 | 157.6 | 94.0 | 1.68 | 151.3 | 18.5 | 12.0 | 13.13 | 46.2 | 52.6 | 94.4 | 320.5 | 1.6 |
| FREEPORT MCMORAN INC | 12/82 | 22.3 | 1550.7 | 735.1 | 2.11 | 747.9 | 71.8 | 65.9 | 23.51 | 62.4 | 172.6 | 479.8 | 503.8 | 2.9 |
| GALAXY OIL CO | 12/81 | 1.6 | 12.6 | 30.0 | .42 | 13.3 | .1 | .1 | 149.81 | 3.5 | 3.7 | 36.1 | 40.2 | .7 |
| GENERAL HYDROCARBONS IN | 6/82 | 1.6 | 12.9 | 3.5 | 3.67 | 1.8 | .1 | .1 | 111.17 | .1 | .1 | 5.5 | .4 | 4.3 |
| GEORESOURCES INC | 12/81 | 2.1 | 8.3 | 4.1 | 1.99 | 4.0 | 1.0 | 1.0 | 8.39 | .2 | .3 | 2.8 | 1.5 | .3 |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GOLDEN OIL CO | 6/82 | 1.7 | 15.8 | 2.6 | 6.02 | 3.7 | .4 | .3 | 50.50 | .5 | 1.3 | 1.9 | 2.1 | .5 |
| GOLDEN TRIANGLE RLTY & | 12/81 | .9 | 11.6 | 1.1 | 10.07 | .0 | -.3 | -.3 | -45.79 | .0 | .1 | .3 | .3 | .1 |
| GREENWOOD RES LTD | 12/81 | 1.3 | 5.8 | 2.5 | 2.34 | .7 | .4 | .4 | 13.65 | .1 | .2 | 1.5 | .1 | 1.4 |
| GULF ENERGY CORP | 4/82 | .3 | 8.1 | 3.0 | 2.70 | 11.0 | .4 | .3 | 29.61 | .3 | .5 | 1.2 | .8 | .9 |
| HADSON PETE CORP | 12/81 | 4.6 | 61.6 | 38.6 | 1.59 | 11.9 | 15.9 | 10.5 | 5.86 | 5.2 | 1.8 | 60.2 | 34.0 | 6.8 |
| HAMILTON BROS PETE CORP | 12/81 | 11.9 | 160.9 | 188.2 | .86 | 160.4 | 33.1 | 19.2 | 8.38 | 12.7 | 24.2 | 55.7 | 78.0 | 3.6 |
| HARKEN OIL & GAS INC | 12/81 | 2.5 | 10.2 | 21.5 | .48 | 3.9 | -3.0 | -2.7 | -3.79 | .5 | 2.0 | 7.8 | 7.1 | .0 |
| HENDERSON PETE CORP | 12/81 | 1.0 | 8.3 | 3.2 | 2.58 | 1.5 | -.3 | -.3 | -32.82 | .3 | .5 | 3.7 | 2.1 | .1 |
| HERSHEY OIL CORP | 12/81 | 6.6 | 38.0 | 15.3 | 2.49 | 6.1 | 1.7 | .9 | 40.96 | .0 | 2.0 | 7.9 | .4 | .0 |
| HOTEL INVS TR | 8/82 | 23.6 | 62.3 | 50.3 | 1.24 | 13.0 | 6.7 | 6.7 | 9.31 | 4.0 | .0 | .0 | 33.4 | 3 2 |
| HOWELL PETE CORP | 12/82 | 20.4 | 109.9 | 96.4 | 1.14 | 72.5 | 13.1 | 7.4 | 14.78 | N/M | 8.5 | 15.1 | 1.8 | 1.3 |
| INEXCO OIL CO | 12/82 | 8.6 | 210.5 | 251.5 | .84 | 217.5 | 26.7 | 18.9 | 11.16 | 49.3 | 75.2 | 203.9 | 398.5 | 16.6 |
| INTERCONTINENTAL ENERGY | 9/82 | 3.1 | 10.6 | 6.6 | 1.61 | 6.8 | -3.8 | -3.8 | -2.77 | 1.0 | 4.0 | 2.9 | .1 | 5.1 |
| JAYTEX OIL & GAS CO | 12/81 | 1.5 | 7.5 | 1.6 | 4.67 | 1.2 | .0 | .0 | 152.84 | .3 | .8 | 4.8 | 2.2 | .8 |
| K R M PETE CORP | 12/81 | 4.3 | 9.6 | 10.3 | .93 | 5.5 | 1.4 | 1.2 | 7.99 | .1 | 1.6 | 5.4 | .0 | .0 |
| KEBA OIL & GAS CO | 8/82 | .7 | 8.7 | 5.1 | 1.71 | .8 | .1 | .1 | 97.54 | .0 | .3 | 1.1 | .0 | .0 |
| KIRBY EXPL CO | 12/81 | 7.6 | 125.1 | 77.9 | 1.61 | 62.0 | 12.1 | 11.1 | 11.23 | 4.5 | 7.0 | 61.8 | 54.0 | 2.5 |
| LEAR PETE CORP | 12/82 | 18.0 | 139.4 | 83.3 | 1.67 | 203.4 | 6.8 | 5.9 | 23.77 | 31.8 | 48.9 | 127.4 | 261.0 | 1.3 |
| LOUISIANA LD & EXPL CO | 12/82 | 32.0 | 1215.5 | 839.4 | 1.45 | 1182.0 | 113.6 | 76.3 | 15.93 | 44.0 | 266.4 | 440.9 | 356.1 | 9.6 |
| MAGIC CIRCLE ENERGY COR | 12/81 | 2.3 | 30.0 | 16.0 | 1.88 | 39.3 | 9.4 | 5.9 | 5.07 | 4.4 | 4.2 | 36.3 | 34.3 | 1.7 |
| MAY PETE INC | 12/81 | 10.4 | 69.4 | 70.9 | .98 | 30.4 | 9.1 | 5.9 | 11.83 | 2.6 | 8.4 | 25.0 | 26 2 | .7 |
| MAYNARD OIL CO | 12/81 | 6.0 | 37.7 | 30.6 | 1.23 | 43.8 | 6.5 | 4.5 | 8.34 | 2.1 | 16.4 | 31.8 | 22.4 | .3 |
| MCCORMICK OIL & GAS CO | 12/82 | 7.8 | 70.1 | 26.3 | 2.66 | 31.5 | -16.0 | -7.2 | -9.70 | 5.4 | 8.2 | 30.7 | 38.6 | 13.1 |
| MCFARLAND ENERGY INC | 12/81 | 9.4 | 41.5 | 22.3 | 1.86 | 17.0 | 7.7 | 4.5 | 9.29 | .0 | 2.1 | 9.1 | .0 | .0 |
| MESA PETE CO | 12/82 | 12.4 | 826.8 | 416.9 | 1.98 | 374.9 | 195.5 | 129.9 | 6.36 | 97.6 | 124.2 | 314.5 | 722.1 | 34.0 |
| MID AMER PETE INC | 8/82 | 2.1 | 27.7 | 4.9 | 5.67 | 12.8 | 2.3 | 1.3 | 21.29 | .4 | .7 | 3.7 | 1.6 | 1.8 |
| MITCHELL ENERGY & DEV C | 1/82 | 19.8 | 946.3 | 388.2 | 2.44 | 1064.8 | 184.7 | 115.2 | 8.21 | 107.7 | 95.8 | 449.1 | 779.7 | 22.7 |
| NATOMAS CO | 12/82 | 15.8 | 818.3 | 1087.0 | .75 | 1587.0 | 160.9 | 44.0 | 18.60 | 134.5 | 424.2 | 802.4 | 1129.4 | 6.5 |
| NORRIS OIL CO | 12/81 | 4.0 | 12.9 | 8.9 | 1.45 | 2.7 | .1 | .1 | 207.68 | 1.4 | .3 | 7.0 | 2.1 | .7 |
| NORTH AMERN RTYS INC | 4/82 | 14.3 | 94.0 | 70.5 | 1.33 | 111.2 | 15.5 | 9.5 | 9.89 | .6 | 14.4 | 27.8 | 5.1 | .8 |
| NUGGET OIL CORP | 4/82 | 1.0 | 10.2 | 8.8 | 1.15 | 7.5 | .8 | .8 | 12.63 | .5 | .4 | 11.7 | 10.5 | .3 |
| ORIGINALA PETE INC | 6/82 | 1.3 | 10.2 | 6.6 | 1.53 | 6.5 | -1.7 | -1.7 | -6.05 | 1.0 | 1.9 | 2.1 | 4.6 | 1.3 |
| OXOCO | 12/81 | 11.0 | 75.8 | 23.2 | 3.27 | 27.1 | 6.5 | 5.6 | 13.62 | 8.3 | 6.1 | 62.0 | 70.9 | .0 |
| PARK OHIO INDS INC DEL | 12/82 | 14.0 | 77.4 | 96.7 | .80 | 176.8 | 15.6 | 10.3 | 7.50 | 4.1 | 11.3 | 14.6 | 24.7 | 1.5 |
| PATTON OIL CO | 3/82 | 2.5 | 6.3 | 3.7 | 1.71 | 3.8 | .5 | .4 | 15.56 | .5 | .7 | 4.0 | 3.0 | .1 |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PETRO LEWIS CORP | 6/82 | 10.0 | 184.6 | 127.8 | 1.45 | 240.7 | 32.0 | 20.6 | 8.96 | 83.3 | 56.3 | 325.7 | 555.5 | 12.5 |
| PETROL INDS INC | 12/81 | 6.1 | 12.3 | 2.6 | 4.72 | 2.9 | 1.1 | .9 | 13.98 | .0 | .1 | .6 | .3 | .1 |
| PETROLEUM DEV CORP | 12/81 | 2.1 | 13.7 | 8.1 | 1.71 | 11.7 | .8 | 1.2 | 11.09 | 1.7 | .8 | 5.2 | 13.0 | 1.2 |
| POGO PRODUCING CO | 12/82 | 24.3 | 583.2 | 306.3 | 1.90 | 278.0 | 86.3 | 51.3 | 11.37 | 46.9 | 123.5 | 321.1 | 434[illegible] | 4.4 |
| POLLOCK PETE INC | 12/81 | .7 | 9.0 | 6.6 | 1.37 | .3 | -.4 | -.4 | -22.87 | .0 | .3 | 8.2 | 3.6 | .1 |
| | | | | | | | | | | | | | | |
| PREMIER RES LTD COLO | 9/82 | 1.4 | 6.4 | 3.6 | 1.81 | 13.2 | -2.2 | -1.7 | -3.81 | 3.1 | 4.4 | 10.2 | .6 | 19.8 |
| PRESIDIO OIL CO | 6/82 | 4.6 | 25.5 | 21.7 | 1.18 | 6.8 | 1.1 | .9 | 27.52 | .6 | 2.1 | 6.0 | 4.3 | .0 |
| RANGER OIL LTD | 12/82 | 7.5 | 456.3 | 127.4 | 3.58 | 208.2 | 98.4 | 28.2 | 16.19 | 15.9 | 40.9 | 44.4 | 17.7 | 107.0 |
| REGAL PETE LTD | 8/82 | .6 | 6.2 | 2.4 | 2.56 | 2.5 | 1.4 | .9 | 6.97 | .0 | .5 | 1.7 | .0 | .0 |
| SABINE CORP | 12/82 | 20.4 | 295.1 | 175.6 | 1.68 | 183.5 | 36.7 | 23.2 | 12.73 | 15.2 | 43.9 | 61.8 | 100.8 | .1 |
| | | | | | | | | | | | | | | |
| SAXON OIL CO | 12/81 | .9 | 18.6 | 23.7 | .78 | 25.9 | 1.6 | .7 | 26.07 | 14.8 | 5.9 | 92.7 | 19.3 | 77.1 |
| SENECA OIL CO | 9/82 | 2.8 | 19.5 | 15.2 | 1.29 | 19.7 | -5.4 | -4.6 | -4.26 | 8.9 | 7.2 | 34.4 | 59.4 | 1.6 |
| SOUTHLAND RTY CO | 12/81 | 17.6 | 785.1 | 106.0 | 7.40 | 397.6 | 58.8 | 28.8 | 27.27 | 56.7 | 71.6 | 133.0 | 425.3 | 17.3 |
| STATEX PETE INC | 10/82 | 9.1 | 26.9 | 22.6 | 1.19 | 11.8 | 1.9 | 1.3 | 21.40 | N/M | 4.0 | 7.4 | .2 | .9 |
| SUPERIOR OIL CO | 12/82 | 35.0 | 4457.8 | 2308.1 | 1.93 | 2040.5 | 428.3 | 223.4 | 19.95 | 156.9 | 476.4 | 1041.3 | 1278.4 | 57.8 |
| | | | | | | | | | | | | | | |
| TEXAS AMERN ENERGY CORP | 12/81 | 3.8 | 25.6 | 28.1 | .91 | 250.2 | -1.7 | -.6 | -43.05 | 12.7 | 12.3 | 22.6 | 67.8 | 15.4 |
| TEXAS AMERN RES INC | 12/81 | .6 | 8.0 | 2.3 | 3.53 | .7 | -.9 | -.6 | -14.28 | .7 | .3 | 4.7 | 5.5 | .9 |
| TEXAS GENL RES INC | 12/81 | 1.5 | 9.0 | 28.5 | .32 | 38.3 | 16.3 | 10.4 | .87 | 3.1 | 1.9 | 60.6 | 66.0 | .6 |
| TEXAS INTL CO | 12/82 | 6.0 | 153.4 | 145.3 | 1.06 | 166.7 | 17.7 | 4.3 | 35.73 | 52.0 | 53.6 | 131.9 | 388.1 | 10.2 |
| TEXON ENERGY CORP | 4/82 | 4.1 | 23.6 | 3.1 | 7.61 | 3.0 | .3 | .3 | 87.24 | .6 | .8 | 1.0 | 3.1 | .2 |
| | | | | | | | | | | | | | | |
| TIPPERARY CORP | 9/82 | 5.0 | 29.8 | 46.1 | .65 | 60.2 | -13.8 | -6.8 | -4.39 | 10.7 | 10.1 | 37.5 | 80.9 | 10.1 |
| TOWNER PETE CO | 3/82 | 4.8 | 37.6 | 42.3 | .89 | 136.4 | 3.4 | 3.1 | 11.95 | 8.0 | 3.6 | 69.8 | 72.6 | 13.6 |
| TRITON ENERGY CORP | 5/82 | 11.9 | 68.9 | 49.7 | 1.39 | 38.4 | 7.8 | 4.0 | 17.15 | 4.6 | 7.7 | 33.7 | 40.7 | 9.5 |
| UNION PAC CORP | 12/82 | 52.7 | 6026.3 | 3888.0 | 1.55 | 5818.3 | 418.2 | 326.8 | 18.44 | 183.1 | 394.4 | 845.8 | 2644.1 | 149.6 |
| UNIVERSAL RES CORP | 10/82 | 6.4 | 56.3 | 101.2 | .56 | 58.1 | 7.7 | 6.6 | 8.52 | 10.1 | 20.6 | 97.2 | 86.4 | 2.1 |
| | | | | | | | | | | | | | | |
| WAINOCO OIL CORP | 12/81 | 5.4 | 57.0 | 70.5 | .81 | 42.0 | -9.2 | -6.2 | -9.18 | 17.0 | 14.1 | 72.2 | 125.5 | 7.6 |
| WICHITA INDS INC | 12/82 | 5.9 | 17.3 | 7.7 | 2.25 | 8.9 | -1.7 | -.8 | -21.67 | 1.2 | 2.0 | 5.2 | 6.9 | .3 |
| WISER OIL CO DEL | 12/81 | 18.1 | 165.1 | 84.5 | 1.95 | 56.9 | 25.0 | 15.0 | 10.98 | .0 | 8.8 | 22.4 | .0 | .0 |
| WOODS PETE CORP | 12/82 | 23.4 | 275.5 | 120.1 | 2.29 | 83.4 | 36.7 | 23.0 | 11.99 | 2.9 | 25.4 | 47.9 | 21.0 | .0 |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CANADIAN PRODUCERS | | | | | | | | | | | | | | |
| BANISTER CONTL LTD | 3/82 | 7.5 | 37.8 | 30.5 | 1.24 | 173.8 | -2.1 | 3.8 | 9.97 | 7.4 | 4.5 | 2.9 | 7.3 | 19.4 |
| BLUEWATER OIL & GAS LTD | 4/82 | 3.9 | 15.8 | 5.9 | 2.68 | 3.8 | 1.2 | 1.0 | 16.38 | .0 | 1.3 | 2.2 | .0 | .0 |
| BOW VALLEY INDS LTD | 12/81 | 16.5 | 583.1 | 140.8 | 4.14 | 403.8 | 40.3 | 39.8 | 14.64 | 65.1 | 45.3 | 341.9 | 516.7 | 18.9 |
| CANADIAN OCCIDENTAL PET | 12/82 | 11.4 | 236.0 | 117.9 | 2.00 | 171.9 | 43.6 | 23.9 | 9.89 | 11.9 | 25.9 | 41.5 | 75.7 | 6.5 |
| DISCOVERY OIL LTD | 12/81 | 1.0 | 9.7 | 7.7 | 1.26 | 6.5 | -.2 | -.2 | -54.31 | .4 | .7 | 7.3 | 4.2 | .0 |
| DOME PETE LTD | 12/82 | 3.5 | 868.9 | 588.6 | 1.48 | 2381.8 | -95.5 | -300.2 | -2.89 | 700.7 | 254.5 | 696.1 | 3489.9 | 1994.3 |
| GULF CDA LTD | 12/82 | 13.1 | 2985.8 | 1810.0 | 1.65 | 3806.0 | 304.0 | 163.0 | 18.32 | 90.0 | 142.0 | 506.0 | 661.0 | 23.0 |
| HUSKY OIL LTD | 12/82 | 8.9 | 700.4 | 420.7 | 1.63 | 1249.5 | 18.0 | 14.2 | 49.43 | 142.0 | 116.0 | 356.1 | 757.0 | 134.5 |
| INTER CITY GAS CORP | 12/81 | 9.9 | 133.4 | 113.9 | 1.17 | 477.5 | 21.3 | 9.2 | 14.46 | 43.5 | 15.8 | 75.3 | 173.4 | 108.1 |
| INTERPROVINCIAL PIPE LI | 12/82 | 22.9 | 589.8 | 244.8 | 2.41 | 297.6 | 125.7 | 60.8 | 9.71 | 29.5 | 35.8 | 8.7 | 270.4 | 8.0 |
| NORTH CDN OILS LTD | 12/82 | 11.3 | 64.4 | 53.0 | 1.21 | 22.6 | 12.9 | 9.7 | 6.66 | 1.5 | 1.7 | 7.6 | 38.1 | .2 |
| NUMAC OIL & GAS LTD | 12/81 | 14.8 | 138.9 | 46.3 | 3.00 | 12.4 | -8.1 | -9.2 | -15.13 | 6.9 | 4.1 | 34.4 | 53.5 | .6 |
| PAGE PETE LTD | 12/81 | 4.5 | 16.3 | 12.1 | 1.36 | 25.4 | -5.4 | -5.7 | -2.88 | 12.0 | 6.7 | 73.9 | 107.0 | 4.0 |
| SUNDANCE OIL CO | 12/81 | 6.0 | 63.2 | -11.6 | -5.43 | 45.0 | -18.6 | -14.8 | -4.26 | 28.2 | 13.9 | 52.7 | 169.9 | 11.4 |
| TEXACO CDA INC | 12/82 | 26.8 | 3228.3 | 1314.0 | 2.46 | 3876.0 | 540.0 | 224.0 | 14.41 | 7.0 | 89.0 | 115.0 | 68.0 | 2.0 |
| WORLDWIDE ENERGY CORP | 12/81 | 6.3 | 56.9 | 29.5 | 1.93 | 54.8 | -1.4 | -.6 | -99.14 | 7.2 | 6.3 | 20.8 | 45.5 | .6 |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PIPELINES AND GAS | | | | | | | | | | | | | | |
| DORCHESTER GAS CORP | 8/82 | 10.3 | 178.0 | 138.1 | 1.29 | 1159.1 | 37.8 | 17.8 | N/M | 22.6 | 23.0 | 71.8 | 149.3 | 35.1 |
| ENTEX INC | 6/82 | 22.1 | 475.5 | 229.9 | 2.07 | 1194.4 | 72.1 | 47.7 | 9.98 | 41.3 | 40.6 | 105.3 | 230.5 | 48.1 |
| EQUITABLE GAS CO | 12/81 | 25.6 | 202.4 | 198.4 | 1.02 | 411.1 | 69.2 | 39.4 | 5.14 | 17.5 | 12.8 | 40.8 | 146.0 | 49.6 |
| GULF ENERGY & DEV CORP | 12/81 | 8.7 | 45.3 | 30.1 | 1.50 | 60.1 | 10.0 | 8.0 | 5.63 | 6.2 | 7.2 | 34.5 | 47.5 | 4.0 |
| NORTHWEST ENERGY CO | 12/82 | 16.8 | 273.7 | 383.6 | .71 | 1601.8 | 86.6 | 38.2 | 7.17 | 97.3 | 52.6 | 141.5 | 813.[illegible] | 360.6 |
| ONEOK INC | 8/82 | 24.3 | 292.2 | 337.8 | .86 | 1119.3 | 88.0 | 56.1 | 5.21 | 33.3 | 35.8 | 182.4 | 307.9 | 91.1 |
| PARGAS INC | 12/82 | 40.6 | 167.9 | 86.8 | 1.93 | 271.2 | 23.0 | 12.4 | 13.59 | 3.7 | 13.1 | 10.4 | 27.9 | 6.0 |
| PEOPLES ENERGY CORP | 9/82 | 8.8 | 266.0 | 325.8 | .82 | 1542.5 | 92.0 | 51.3 | 5.19 | 32.8 | 41.2 | 66.9 | 357.4 | 2.2 |
| SOUTHERN UN CO | 12/81 | 18.9 | 191.6 | 199.6 | .96 | 623.9 | 37.1 | 37.9 | 5.06 | 20.2 | 12.7 | 46.8 | 138.9 | 54.1 |
| TENNECO INC | 12/82 | 37.0 | 4959.8 | 5471.0 | .91 | 14979.0 | 1202.0 | 819.0 | 6.06 | 939.0 | 1035.0 | 2103.0 | 5032.0 | 602.0 |
| UGI CORP | 12/81 | 19.4 | 146.0 | 193.6 | .75 | 657.3 | 47.3 | 31.2 | 4.67 | 21.6 | 25.4 | 96.0 | 206.4 | 15.2 |
| WASHINGTON GAS LT CO | 12/82 | 26.8 | 174.1 | 209.8 | .83 | 682.8 | 34.3 | 21.1 | 8.26 | 31.7 | 20.8 | 49.9 | 247.3 | 76.1 |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| DRILLING COMPANIES | | | | | | | | | | | | | | |
| ANGLO ENERGY LTD | 9/82 | 5.0 | 51.6 | 116.3 | .44 | 319.8 | -16.9 | .4 | 116.15 | 22.7 | 29.8 | 70.1 | 128.0 | 37.0 |
| ASTRO DRILLING CO | 9/82 | 2.1 | 5.9 | 12.2 | .48 | 21.8 | -2.0 | -.7 | -8.54 | 2.4 | 2.9 | 9.4 | 17.4 | .6 |
| ATWOOD OCEANICS INC | 9/82 | 24.0 | 94.6 | 81.9 | 1.16 | 95.3 | 40.1 | 24.3 | 3.90 | 6.5 | 11.6 | 30.0 | 32.4 | 10.6 |
| BLOCKER ENERGY CORP | 12/81 | 2.9 | 17.2 | 49.6 | .35 | 136.6 | 11.0 | 4.3 | 3.97 | 18.3 | 14.8 | 136.0 | 141.6 | 3.8 |
| BONRAY DRILLING CORP | 6/82 | 3.1 | 13.7 | 27.3 | .50 | 34.2 | 13.0 | 8.3 | 1.65 | 1.9 | 4.4 | 14.3 | 9.9 | .0 |
| BROWN TOM INC | 3/82 | 7.0 | 275.2 | 116.3 | 2.37 | 216.9 | 29.8 | 20.4 | 13.47 | 15.3 | 24.0 | 96.6 | 132.4 | .6 |
| BUTTES GAS & OIL CO | 12/81 | 8.5 | 35.2 | 37.3 | .94 | 150.6 | 5.4 | -5.0 | -7.06 | 41.8 | 19.5 | 138.4 | 286.0 | 24.1 |
| CRAWFORD ENERGY INC | 6/82 | 3.0 | 10.7 | 8.1 | 1.31 | 17.6 | .0 | .4 | 28.81 | 2.3 | 3.4 | 13.9 | 15.2 | 1.4 |
| DELTA DRILLING CO | 12/81 | 5.1 | 107.2 | 144.2 | .74 | 205.0 | 45.8 | -3.7 | -29.15 | 15.1 | 34.1 | 111.7 | 95.7 | 9.7 |
| DRILLERS INC | 3/82 | 4.4 | 14.6 | 34.0 | .43 | 30.9 | 8.9 | 7.2 | 2.03 | 1.9 | 4.1 | 46.0 | 26.8 | 1.2 |
| GLOBAL MARINE INC | 12/82 | 8.9 | 274.7 | 476.3 | .58 | 455.7 | 91.0 | 85.0 | 3.23 | 84.7 | 70.0 | 473.8 | 641.7 | 38.6 |
| HELMERICH & PAYNE INC | 9/82 | 19.8 | 496.8 | 365.7 | 1.36 | 338.2 | 114.4 | 75.7 | 6.56 | 16.7 | 78.7 | 108.8 | 105.6 | 27.1 |
| KANEB SVCS INC | 12/82 | 15.4 | 364.9 | 318.5 | 1.15 | 595.6 | 71.4 | 64.2 | 5.69 | 46.7 | 60.8 | 139.8 | 335.3 | 59.7 |
| KENAI CORP | 1/82 | 4.9 | 23.6 | 71.5 | .33 | 136.1 | 21.3 | 14.5 | 1.62 | 9.4 | 10.2 | 65.1 | 83.4 | 1.1 |
| MGF OIL CORP | 12/81 | 1.7 | 27.6 | 98.2 | .28 | 113.9 | 13.5 | 9.9 | 2.78 | 20.9 | 21.5 | 176.6 | 172.9 | 3.1 |
| MIDLAND SOUTHWEST CORP | 12/81 | 2.3 | 10.8 | 26.4 | .41 | 40.1 | 5.3 | 4.8 | 2.27 | 3.9 | 6.2 | 50.7 | 36.6 | .8 |
| MORAN ENERGY INC | 12/82 | 13.1 | 132.5 | 117.2 | 1.13 | 93.8 | 13.2 | 8.3 | 15.90 | 11.0 | 24.8 | 69.9 | 108.2 | 5.2 |
| NICKLOS OIL & GAS CO | 12/82 | 4.4 | 31.0 | 71.7 | .43 | 45.6 | -15.6 | -7.2 | -4.30 | 3.5 | 15.4 | 33.1 | 30.9 | .0 |
| NOBLE AFFILIATES INC | 12/82 | 14.8 | 656.9 | 388.7 | 1.69 | 397.9 | 111.3 | 70.3 | 9.35 | 15.9 | 103.0 | 172.9 | 124.5 | 6.0 |
| OCEAN DRILLING & EXPL ( | 12/82 | 24.5 | 1264.2 | 775.1 | 1.63 | 979.6 | 414.6 | 191.9 | 6.59 | 19.9 | 202.3 | 331.4 | 155.4 | 23.4 |
| PARKER DRILLING CO | 8/82 | 9.0 | 259.9 | 383.1 | .68 | 615.9 | 123.3 | 76.3 | 3.41 | 51.2 | 75.4 | 157.7 | 332.8 | 39.3 |
| RATLIFF DRILLING & EXPL | 9/82 | 4.8 | 14.1 | 23.0 | .61 | 37.4 | 1.8 | 2.6 | 5.38 | 3.3 | 7.1 | 22.8 | 24.8 | 6.3 |
| READING & BATES CORP | 12/82 | 13.6 | 378.6 | 461.0 | .82 | 516.8 | 143.4 | 75.6 | 5.01 | 44.4 | 64.0 | 411.9 | 453.3 | 20.8 |
| RIO GRANDE DRILLING CO | 1/82 | 2.4 | 5.8 | 10.4 | .56 | 14.2 | 2.6 | 2.5 | 2.31 | 1.9 | 1.7 | 8.1 | 8.8 | 1.1 |
| ROWAN COS INC | 12/82 | 12.4 | 597.6 | 509.4 | 1.17 | 400.4 | 191.4 | 119.4 | 5.00 | 15.2 | 40.4 | 185.6 | 71.5 | 16.3 |
| SAGE DRILLING INC | 6/82 | 5.0 | 8.8 | 13.8 | .64 | 22.3 | 4.5 | 3.0 | 2.96 | .1 | 1.4 | 6.3 | 1.2 | 1.0 |
| SAGE ENERGY CO | 6/82 | 8.6 | 107.0 | 58.8 | 1.82 | 74.1 | 27.9 | 24.6 | 4.35 | 3.4 | 14.6 | 44.6 | 30.0 | .0 |
| SEDCO INC | 6/82 | 33.3 | 735.3 | 351.0 | 2.10 | 522.6 | 448.8 | 260.0 | 2.83 | 49.3 | 56.8 | 125.0 | 242.6 | 52.1 |
| SOUTH TEX DRILLING & EX | 12/81 | 3.5 | 9.8 | 13.3 | .74 | 11.2 | 3.2 | 2.8 | 3.52 | .8 | 1.5 | 21.6 | 15.8 | 1.2 |
| TRANSCONTINENTAL ENERGY | 12/81 | 4.5 | 24.5 | 44.9 | .55 | 91.5 | 14.9 | 11.6 | 2.11 | 7.4 | 12.6 | 31.1 | 49.2 | 5.5 |
| TUCKER DRILLING INC | 3/82 | 8.9 | 21.3 | 19.6 | 1.09 | 41.5 | 8.3 | 5.2 | 4.06 | .2 | 4.2 | 11.5 | 1.7 | .3 |
| UNIT DRILLING & EXPL CO | 12/81 | 6.1 | 43.9 | 55.9 | .79 | 75.8 | 26.3 | 17.3 | 2.54 | 4.6 | 11.7 | 60.6 | 44.0 | 2.1 |
| VERNA CORP | 6/82 | 2.0 | 8.7 | 18.9 | .46 | 71.9 | -3.4 | .8 | 11.29 | 4.7 | 13.7 | 22.6 | 29.6 | 4.1 |
| WESTBURNE INTL INDS LTD | 3/82 | 12.9 | 134.6 | 185.3 | .73 | 1051.1 | 27.3 | 9.5 | 14.18 | 35.7 | 20.9 | 40.3 | 59.1 | 158.4 |
| ZAPATA CORP | 9/82 | 16.6 | 317.6 | 399.5 | .80 | 537.1 | 176.1 | 95.3 | 3.33 | 53.4 | 52.8 | 182.6 | 497.8 | 16.5 |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **OIL WELL & EQUIPMENT SERVICES** | | | | | | | | | | | | | | |
| BAKER INTL CORP | 9/82 | 18.1 | 1261.9 | 1182.1 | 1.07 | 2535.1 | 416.2 | 248.6 | 5.08 | 74.2 | 111.6 | 452.3 | 608.6 | 39.6 |
| BIG THREE INDS INC | 12/82 | 21.1 | 896.0 | 609.8 | 1.47 | 767.8 | 147.3 | 86.8 | 10.32 | 22.1 | 63.6 | 162.3 | 202.5 | 20.3 |
| BOLT TECHNOLOGY CORP | 6/82 | 13.6 | 46.6 | 19.4 | 2.40 | 21.1 | 8.8 | 5.2 | 8.89 | .0 | 1.0 | 3.4 | .1 | .0 |
| BRALORNE RES LTD | 12/82 | 4.1 | 83.5 | 69.1 | 1.21 | 185.6 | -5.5 | -.7 | 123.93 | 20.5 | 17.7 | 30.9 | 99.8 | 45.3 |
| CAMCO INC | 12/82 | 15.4 | 111.5 | 78.5 | 1.42 | 184.4 | 32.0 | 17.9 | 6.21 | 4.6 | 6.6 | 10.3 | 20.9 | 8.2 |
| CAMERON IRON WKS INC | 6/82 | 19.3 | 583.7 | 586.6 | .99 | 1147.3 | 237.3 | 152.6 | 3.83 | 56.6 | 53.6 | 215.5 | 289.1 | 118.9 |
| CRUTCHER RES CORP | 12/81 | 6.8 | 64.0 | 83.6 | .78 | 256.0 | 36.3 | 24.8 | 2.61 | 11.5 | 18.4 | 67.0 | 108.0 | 11.1 |
| DORCHESTER GAS CORP | 8/82 | 10.3 | 178.0 | 138.1 | 1.29 | 1159.1 | 37.8 | 17.8 | N/M | 22.6 | 23.0 | 71.8 | 149.3 | 35.1 |
| DRESSER INDS INC | 10/82 | 19.0 | 1497.7 | 2019.2 | .74 | 4160.6 | 242.8 | 172.3 | 8.69 | 59.5 | 191.9 | 365.7 | 390.1 | 155.2 |
| EDISON SAULT ELEC CO | 12/81 | 12.0 | 5.6 | 5.7 | .98 | 14.4 | 1.6 | 1.0 | 5.53 | .8 | .9 | 2.9 | 6.5 | 2.5 |
| ENTERRA CORP | 12/81 | 17.3 | 154.1 | 160.5 | .96 | 250.9 | 85.0 | 51.6 | 2.99 | 3.8 | 27.7 | 94.5 | 92.0 | 1.9 |
| GALVESTON HOUSTON CO | 12/81 | 10.9 | 61.8 | 96.8 | .64 | 221.7 | 38.1 | 22.6 | 2.73 | 8.6 | 9.0 | 43.5 | 87.1 | 9.9 |
| GEARHART INDS INC | 1/82 | 20.3 | 312.5 | 178.4 | 1.75 | 344.8 | 52.3 | 31.6 | 9.87 | 12.3 | 29.6 | 93.6 | 87.2 | 21.1 |
| HALLIBURTON CO | 12/82 | 33.9 | 3999.8 | 3482.1 | 1.15 | 7281.8 | 824.9 | 496.8 | 8.05 | 123.7 | 366.8 | 488.3 | 745.3 | 27.2 |
| HUGHES TOOL CO | 12/82 | 18.1 | 1000.5 | 1255.9 | .80 | 1595.9 | 202.2 | 147.6 | 6.78 | 88.7 | 110.1 | 310.8 | 662.6 | 81.5 |
| MARK PRODS INC | 12/82 | 3.1 | 23.8 | 22.3 | 1.06 | 38.6 | -.9 | -.2 | 151.29 | .9 | 2.7 | 2.0 | 7.7 | 3.0 |
| NEWPARK RES INC | 12/81 | 5.9 | 78.4 | 124.7 | .63 | 271.9 | 39.6 | 23.0 | 3.41 | 9.2 | 12.6 | 56.2 | 61.7 | 8.5 |
| NL INDS INC | 12/82 | 16.5 | 1018.3 | 1150.8 | .88 | 2213.5 | 289.7 | 188.8 | 5.39 | 77.1 | 121.0 | 306.1 | 555.0 | 25.4 |
| NUCORP ENERGY INC | 12/81 | .4 | 7.2 | 115.3 | .06 | 411.3 | 7.2 | 1.4 | 5.00 | 44.8 | 30.0 | 195.5 | 444.7 | 35.9 |
| OCEANEERING INTL INC | 10/82 | 11.8 | 75.3 | 51.4 | 1.46 | 118.6 | 16.6 | 11.0 | 6.82 | N/M | 8.8 | 14.8 | .2 | .9 |
| OFFSHORE LOGISTICS INC | 6/82 | 15.3 | 43.2 | 63.4 | .68 | 181.6 | 9.9 | 11.3 | 3.81 | 20.3 | 16.1 | 25.5 | 152.8 | 13.4 |
| PENN CENT CORP | 12/82 | 29.6 | 882.5 | 1467.7 | .60 | 3165.4 | 254.5 | 131.5 | 6.71 | 35.7 | 107.9 | 167.8 | 453.7 | 59.0 |
| PETROLANE INC | 9/82 | 13.3 | 689.8 | 511.5 | 1.35 | 1978.4 | 151.9 | 104.3 | 6.61 | 25.7 | 77.5 | 152.1 | 227.9 | 13.1 |
| PETROLEUM EQUIP TOOLS C | 12/82 | 8.4 | 87.6 | 116.4 | .75 | 136.3 | 15.6 | 12.9 | 6.79 | 6.6 | 27.2 | 49.3 | 53.2 | .6 |
| PETROLITE CORP | 10/82 | 28.1 | 333.7 | 142.0 | 2.35 | 302.6 | 48.5 | 29.3 | 11.39 | 1.6 | 12.3 | 24.2 | 10.0 | 2.9 |
| PYRAMID OIL CO | 12/81 | 4.3 | 21.6 | 9.4 | 2.28 | 12.4 | 2.1 | 1.6 | 13.74 | .2 | .9 | 2.7 | .2 | .3 |
| SCHLUMBERGER LTD | 12/82 | 43.5 | 12729.9 | 5226.4 | 2.44 | 6025.4 | 1799.4 | 1348.2 | 9.44 | 116.6 | 584.0 | 1094.3 | 462.2 | 510.0 |
| SEIS PROS INC | 3/82 | 7.0 | 27.3 | 17.9 | 1.52 | 45.4 | 11.0 | 6.7 | 4.10 | 1.1 | 3.7 | 14.3 | 7.5 | 2.6 |
| SEISCOM DELTA INC | 9/82 | 5.1 | 20.5 | 49.4 | .41 | 168.8 | -6.5 | -3.2 | -6.36 | 14.6 | 15.0 | 22.6 | 71.1 | 13.4 |
| SERVICE FRACTURING CO | 3/82 | 6.4 | 19.6 | 21.0 | .93 | 26.2 | 5.8 | 3.9 | 4.97 | .2 | 2.3 | 10.0 | 1.1 | 1.1 |
| SMITH INTL INC | 12/82 | 23.3 | 526.5 | 664.8 | .79 | 1072.9 | 132.8 | 82.3 | 6.40 | 23.1 | 54.0 | 152.5 | 138.3 | 145.5 |
| TIDEWATER INC | 3/82 | 24.3 | 400.8 | 303.3 | 1.32 | 466.3 | 116.8 | 71.5 | 5.61 | 17.7 | 47.0 | 145.4 | 185.8 | 5.6 |
| TRICO INDS INC | 12/82 | 8.0 | 64.4 | 55.3 | 1.16 | 109.9 | 7.5 | 4.8 | 13.31 | 3.5 | 3.9 | 14.8 | 20.6 | 11.7 |
| WEATHERFORD INTL INC | 12/81 | 9.4 | 81.6 | N/M | .82 | 229.8 | 38.8 | 24.5 | 3.33 | 4.8 | 12.5 | 33.5 | 41.1 | 8.6 |
| WESTERN CO NORTH AMER | 12/82 | 7.1 | 308.7 | 382.2 | .81 | 676.5 | 70.8 | 56.6 | 5.45 | 89.4 | 79.1 | 240.3 | 634.9 | 26.4 |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| XOIL ENERGY RES INC | 8/82 | 3.0 | 19.4 | 3.1 | 6.23 | 6.2 | -12.9 | -10.1 | -1.92 | 1.3 | 1.7 | 1.7 | .5 | 11.0 |
| YANKEE OIL & GAS INC | 6/82 | 17.1 | 57.4 | 12.9 | 4.45 | 33.2 | 4.5 | 2.7 | 21.45 | .9 | .9 | 14.0 | 13.2 | .1 |
| REFINERS | | | | | | | | | | | | | | |
| AMERICAN PETROFINA INC | 12/82 | 53.0 | 574.0 | 563.1 | 1.02 | 2290.5 | 87.5 | 54.4 | 10.55 | 20.3 | 105.5 | 155.3 | 198.3 | 69.2 |
| ASAMERA INC | 12/82 | 21.1 | 149.0 | 75.5 | 1.97 | 443.4 | .9 | 3.6 | 41.43 | 8.7 | 37.7 | 89.3 | 41.8 | 40.1 |
| ASHLAND OIL INC | 9/82 | 31.1 | 827.4 | 1047.2 | .79 | 8864.7 | 292.2 | 180.9 | 4.57 | 88.3 | 173.4 | 474.7 | 760.8 | 58.6 |
| CHARTER CO | 12/82 | 11.5 | 248.1 | 526.0 | .47 | 3970.3 | 108.2 | 35.3 | 7.04 | 70.7 | 34.6 | 41.1 | 378.3 | 32.6 |
| COASTAL CORP | 12/82 | 20.1 | 435.6 | 523.6 | .83 | 5799.4 | 110.7 | 65.6 | 6.64 | 150.3 | 147.5 | 406.2 | 983.0 | 394.8 |
| COMMONWEALTH OIL REFNG | 12/81 | .4 | 9.0 | -57.3 | -.16 | 1012.9 | -261.2 | -212.3 | -.04 | 41.4 | 161.0 | 3.6 | 158.5 | 35.9 |
| CROWN CENT PETE CORP | 12/82 | 18.5 | 115.1 | 192.2 | .60 | 1772.5 | 5.3 | 7.0 | 16.40 | 14.0 | 51.8 | 77.3 | 106.0 | 8.2 |
| CRYSTAL OIL CO | 12/81 | 16.5 | 345.5 | 69.8 | 4.95 | 315.4 | 1.1 | 1.2 | 291.28 | 35.4 | 44.6 | 160.1 | 245.9 | 1.7 |
| HOLLY CORP | 7/82 | 10.3 | 83.8 | 65.8 | 1.27 | 538.6 | 16.5 | 10.5 | 7.97 | .7 | 10.7 | 22.5 | 4.4 | 1.1 |
| HOWELL CORP | 12/82 | 12.1 | 58.4 | 72.1 | .81 | 224.0 | 11.7 | 2.3 | 25.76 | 2.2 | 11.8 | 21.6 | 8.2 | 6.1 |
| MARION CORP | 1/82 | 1.7 | 22.1 | 70.5 | .31 | 444.5 | -21.3 | -10.2 | -2.17 | 12.0 | 11.5 | 26.1 | 82.0 | 2.3 |
| MEENAN OIL INC | 6/82 | 6.3 | 15.4 | 17.3 | .89 | 294.3 | .2 | .3 | 53.68 | 5.2 | 4.2 | 10.7 | 21.7 | 6.8 |
| PAULEY PETE INC | 8/82 | 6.6 | 19.2 | 11.4 | 1.68 | 202.8 | -10.7 | -10.4 | -1.83 | 8.2 | 13.6 | 15.6 | 55.4 | 6.7 |
| QUAKER ST OIL REFNG COR | 12/82 | 18.8 | 407.5 | 260.9 | 1.56 | 928.9 | 70.4 | 38.6 | 10.57 | 12.4 | 34.6 | 50.3 | 80.6 | 10.7 |
| TESORO PETE CORP | 9/82 | 15.5 | 211.9 | 376.7 | .56 | 2439.9 | 109.8 | 50.1 | 4.23 | 2.9 | 42.1 | 88.0 | 88.2 | 1.4 |
| TOMLINSON OIL INC | 8/82 | 1.4 | 5.5 | 3.0 | 1.84 | 100.5 | -4.3 | -7.8 | -.71 | 4.3 | 3.1 | 4.2 | 31.0 | 2.6 |
| TOSCO CORP | 12/82 | 9.4 | 172.8 | 302.0 | .57 | 3466.0 | 176.4 | 132.4 | 1.31 | 56.1 | 26.3 | 174.3 | 432.7 | 111.0 |
| TOTAL PETE NORTH AMER L | 12/82 | 11.6 | 198.7 | 166.3 | 1.20 | 2195.4 | 18.2 | 12.8 | 15.58 | 54.8 | 65.2 | 83.2 | 349.1 | 44.1 |

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## WEEKLY HUGHES TOOL RIG COUNT
### UNITED STATES

| WEEK | 1980 | 1981 | 1982 | 1983 | 1982 CHANGE UNITS* | 1982 CHANGE % YR/YR | 1983 CHANGE UNITS* | 1983 CHANGE % YR/YR |
|---|---|---|---|---|---|---|---|---|
| 1 | 2506 | 3337 | 4467 | 2756 | -63 | 33.86 | -12 | -38.30 |
| 2 | 2495 | 3383 | 4443 | 2723 | -24 | 31.33 | -33 | -38.71 |
| JAN 3 | 2578 | 3391 | 4438 | 2636 | -5 | 30.88 | -87 | -40.60 |
| 4 | 2631 | 3434 | 4396 | 2538 | -42 | 28.01 | -98 | -42.27 |
| 5 | 2647 | 3451 | 4276 | 2456 | -120 | 23.91 | -82 | -42.56 |
| 6 | 2621 | 3495 | 4199 | 2335 | -77 | 20.14 | -121 | -44.39 |
| FEB 7 | 2622 | 3529 | 4092 | 2223 | -107 | 15.95 | -112 | -45.67 |
| 8 | 2600 | 3534 | 4072 | 2147 | -20 | 15.22 | -76 | -47.27 |
| 9 | 2601 | 3568 | 3959 | 2064 | -113 | 10.96 | -83 | -47.87 |
| 10 | 2621 | 3566 | 3911 | 2043 | -48 | 9.67 | -21 | -47.76 |
| MAR11 | 2667 | 3582 | 3823 | 2014 | -88 | 6.73 | -29 | -47.32 |
| 12 | 2669 | 3605 | 3747 | 2000 | -76 | 3.94 | -14 | -46.62 |
| 13 | 2676 | 3656 | 3639 | 1956 | -108 | -0.46 | -44 | -46.25 |
| 14 | 2659 | 3668 | 3597 | 1882 | -42 | -1.94 | -74 | -47.68 |
| APR15 | 2654 | 3704 | 3509 | 1834 | -88 | -5.26 | -48 | -47.73 |
| 16 | 2646 | 3756 | 3422 | 1807 | -87 | -8.89 | -27 | -47.19 |
| 17 | 2682 | 3784 | 3310 | 1860 | -112 | -12.53 | 53 | -43.81 |
| 18 | 2740 | 3801 | 3312 |  | 2 | -12.87 |  |  |
| MAY19 | 2777 | 3795 | 3222 |  | -90 | -15.10 |  |  |
| 20 | 2786 | 3828 | 3128 |  | -94 | -18.29 |  |  |
| 21 | 2807 | 3842 | 3049 |  | -79 | -20.64 |  |  |
| 22 | 2818 | 3858 | 2931 |  | -118 | -24.03 |  |  |
| JUN23 | 2797 | 3860 | 2907 |  | -24 | -24.69 |  |  |
| 24 | 2806 | 3899 | 2924 |  | 17 | -25.01 |  |  |
| 25 | 2857 | 4008 | 2906 |  | -18 | -27.50 |  |  |
| 26 | 2889 | 4007 | 2874 |  | -32 | -28.28 |  |  |
| 27 | 2901 | 3984 | 2816 |  | -58 | -29.32 |  |  |
| JUL28 | 2911 | 3970 | 2743 |  | -73 | -30.91 |  |  |
| 29 | 2943 | 4027 | 2694 |  | -49 | -33.10 |  |  |
| 30 | 2907 | 4009 | 2730 |  | 36 | -31.90 |  |  |
| 31 | 2971 | 4054 | 2671 |  | -59 | -34.11 |  |  |
| AUG32 | 3040 | 4116 | 2656 |  | -15 | -35.47 |  |  |
| 33 | 3020 | 4142 | 2645 |  | -11 | -36.14 |  |  |
| 34 | 3050 | 4151 | 2600 |  | -45 | -37.36 |  |  |
| 35 | 3069 | 4194 | 2528 |  | -72 | -39.72 |  |  |
| 36 | 3060 | 4184 | 2526 |  | -2 | -39.63 |  |  |
| SEP37 | 3051 | 4224 | 2499 |  | -27 | -40.84 |  |  |
| 38 | 3115 | 4249 | 2466 |  | -33 | -41.96 |  |  |
| 39 | 3124 | 4309 | 2439 |  | -27 | -43.40 |  |  |
| 40 | 3130 | 4338 | 2429 |  | -10 | -44.01 |  |  |
| OCT41 | 3115 | 4368 | 2418 |  | -11 | -44.64 |  |  |
| 42 | 3126 | 4361 | 2379 |  | -39 | -45.45 |  |  |
| 43 | 3164 | 4339 | 2380 |  | 1 | -45.15 |  |  |
| 44 | 3189 | 4346 | 2413 |  | 33 | -44.48 |  |  |
| 45 | 3210 | 4437 | 2456 |  | 43 | -44.65 |  |  |
| NOV46 | 3209 | 4469 | 2477 |  | 21 | -44.57 |  |  |
| 47 | 3231 | 4443 | 2555 |  | 78 | -42.49 |  |  |
| 48 | 3231 | 4487 | 2603 |  | 48 | -41.99 |  |  |
| 49 | 3209 | 4505 | 2633 |  | 30 | -41.55 |  |  |
| DEC50 | 3262 | 4525 | 2674 |  | 41 | -40.91 |  |  |
| 51 | 3303 | 4522 | 2708 |  | 34 | -40.11 |  |  |
| 52 | 3328 | 4530 | 2768 |  | 60 | -38.90 |  |  |
| 53 | 3326 |  |  |  |  |  |  |  |
| YEARLY AVERAGE: | 2909 | 3974 | 3105 | 2193 | -33.88 | -19.76 | -50.44 | -44.82 |

* CHANGE IN ACTIVE RIGS FROM PREVIOUS WEEK.

SOURCE: HUGHES TOOL COMPANY

Mr. PICKLE. We thank you, Mr. Smith, and appreciate your summary of your testimony. I notice that you have included a large number of charts, which will be made part of the record. You couldn't comment on all of them, but it is a voluminous production. We thank you for the information.

Now Mr. Dyer, president of Dyco Petroleum Corp.

## STATEMENT OF JAYE F. DYER, PRESIDENT, DYCO PETROLEUM CORP. AND PRESIDENT, OIL INVESTMENT INSTITUTE ACCOMPANIED BY ROBERT R. NATHAN, CHAIRMAN, ROBERT R. NATHAN ASSOCIATES, INC., MINNEAPOLIS, MINN.

Mr. DYER. Our company is an independent oil and gas company, with particular emphasis in the development of natural gas at the present time. We are listed on the New York Stock Exchange. In addition, I am the president of an association of similar companies called the Oil Investment Institute [OII].

By training, I am a petroleum geologist and I have been in the oil and gas industry for 32 years, 25 of which have been in the business of managing public drilling programs or limited partnerships.

I appreciate the opportunity to be here on behalf of the OII and DYCO.

Before I continue, our company and the OII retained Robert Nathan Associates to conduct a study directed to the natural gas industry, and I would like Mr. Nathan at this time to provide a brief overview of his findings.

Mr. PICKLE. Mr. Nathan, will you proceed? Mr. Dyer, you are submitting your statement for the record?

Mr. DYER. I would like to come back after Mr. Nathan has finished, if I may, Mr. Chairman.

Mr. PICKLE. All right, Mr. Nathan.

Mr. NATHAN. Thank you, Mr. Chairman. Very briefly, I would make three points. First of all, this consideration of tax policy takes place in a time of, in my judgment, a continued jeopardy of the United States in terms of its energy resources. We relied last year in a recession year on almost one-third of our total oil use from imports, and given the instability of the major outside sources of energy, and given the fact that if there is a recovery that is significant here in the United States and in the industrial countries, and that would mean more growth in the less developed countries, I believe that our reliance on oil imports will increase, and may very well go back up near where they were just a few years ago, up to nearly half, and I think this poses very serious problems to the health of the American economy, the job creation, to our balance of trade, our balance of payments, and especially to our national security.

It is rather distressing to note that even in the recession last year we did import almost 5 million barrels of oil per day, and spent well over $50 billion, and I think this context is something that we ought to take into account before we make changes in tax laws that would discourage the development of domestic resources.

We do, of course, need to continue on conservation and new resources, but it is going to take a long time to reduce our dependency on imports, unless we use the resources we now have, and that means gas and oil in the fullest possible measure. And we don't know what we have unless we drill, and drill very, very substantially.

My second point is that the present environment is a very discouraging one for drilling and discovering and proving up reserves. With the recession and with the decline in oil prices, and the apparent, which I think is a temporary glut, that there has been a marked decline in drilling. New exploratory drilling for gas in some of the recent months has gone down as much as 25 and as much as nearly 50 percent from the same date a year earlier, and this decline in drilling is a very serious factor at a time when we really need to prove up our reserves very, very much more importantly.

Basically, it is my feeling that our national energy policies are not going to be very constructive and very well based, if we are going to fail to prove up those reserves, and right now there is a great degree of optimism about large gas reserves, but the reason for that is because we have had more drilling in the past 2 or 3 years, because of the attractiveness of it, and the continuation of incentives.

But if this reduction in the incentives were to take place, Mr. Chairman, I do believe that we would not move toward any proving up of reserves, and I think our dependence on oil imports would jeopardize this even more.

What we really need is investment, investment, invesment, and more drilling, and in this very risky sector, our study shows that the returns would really be substantially reduced, as Mr. Dyer will indicate, and I do believe that this tendency to take away the incentives would be a very, very important move against the national interest.

I would just like to add one more point, and that is I noted what Alice Rivlin said yesterday from the Congressional Budget Office, a lady for whom I have great respect, but she talked about the desirability of not permitting differentials. While the independents are not against the oil industry, the large oil companies, nonetheless it must be recognized that they do much more of the wildcatting, and when you put money in the ground, and more than 8 out of 10 prove to be dry or very little producers, the risk is very great, and I think that differentials are justified when risks are different.

Finally, one point I think Dr. Rivlin made, that if you have tax differentials, you reduce efficiency. Well, there is a lot of competition among the independents for land, for drilling, for getting money from the investors, and there is no doubt that the most efficient drilling programs are going to be more successful, and the marketplace indicates that, so I don't think that the argument there is justifiable for in any degree reducing the incentives. If anything, I might say that I think, today, given the international expenditure, the incentives ought to be increased and not reduced.

Thank you.

[The prepared statement follows:]

## STATEMENT OF ROBERT R. NATHAN, CHAIRMAN, ROBERT R. NATHAN ASSOCIATES, INC.

My name is Robert R. Nathan and I am Chairman of Robert R. Nathan Associates, Inc. (RRNA), a firm of consulting economists. I appear on behalf of Dyco Petroleum Corporation and the Oil Investment Institute.

Appropriate government and private energy policies should be formulated in the context of recent, present and prospective developments in the energy field. Otherwise changes in existing policies or the adoption of new policies to cope with the nation's energy problems could prove inadequate or even be counterproductive.

There is a strong probability that the United States and other oil importing nations will again face an energy crisis in the next several years. Such a crisis could come soon if there were an interruption in the flow of oil from the larger exporters of petroleum. We continue to rely heavily on oil from countries and regions where instability and insecurity are constant threats.

Energy problems will again emerge when the United States and the other industrialized nations recover from the still present recession. The developing countries have also suffered slower growth or economic stagnation as their access to new capital and their product markets have diminished. Economic recovery and growth will certainly bring larger demands for energy from all oil importing nations.

It is difficult to forecast accurately what is going to happen to OPEC. However, the probabilities are that OPEC is not going to disappear or become ineffective. The stakes are too high for the OPEC nations to throw away the tremendous advantages they have enjoyed through restricting production and setting very high prices. The recent $5 per barrel decline by OPEC may make a $29 per barrel price seem low to those with short memories. But it is still more than ten times what oil prices were only ten years ago. Were it not for OPEC restrictions on production, the free market price for oil might very well drop further by $10 a barrel or more and that would mean a tremendous reduction in foreign exchange earnings of the oil exporting nations. They know full well that the short-term elasticity of demand for oil is not very great and that drops in oil prices will result in proportionately lower revenues for the oil exporting countries. That certainly is not what they are prepared to experience. Economic recovery in the West will definitely improve the bargaining power of OPEC as well as non-OPEC oil exporters. All exporting countries realize that lower prices will mean lower revenues and that is why non-OPEC exporting nations are inclined to go along with the OPEC cartel.

In 1982 oil imports accounted for nearly one-third of U.S. oil consumption. If we can succeed in keeping United States domestic oil production at the present level over the next few years, economic recovery will require imports to rise to at least 40 percent of total consumption. That will aggravate the United States balance of trade and balance of payments deficits. Oil imports in 1982 totaled over $50 billion. As the economy recovers the outflow of dollars for foreign oil will certainly increase.

American dependence on large petroleum imports will continue unless and until major increases in existing and new sources of energy are developed. Improved efficiency in the use of energy will surely help, but increased supplies will be essential. The high degree of dependence on imports significantly affects the general health of the American economy, job opportunities, our standard of living, and obviously has critical implications for our nation's security.

Proposals to reduce or eliminate incentives to stimulate exploration for oil and gas fail to take into account the dangers and disadvantages associated with heavy reliance on petroleum imports. We must make every reasonable effort to expand our domestic sources of energy rather than wait for other crises, especially since long lead times are needed to seek and develop greater supplies of traditional as well as new sources of energy. We must not allow temporary surpluses to obscure the serious energy challenges that lie ahead.

This country has plenty of coal, but environmental and transportation constraints may well limit the expanded use of coal. There have been no commitments to new nuclear power-plants for several years. The panic button has been turned off on practically all urgent measures to seek new sources of energy. In fact, further progress in increasing efficiency in energy use seems to be in jeopardy.

It is essential that we do everything within our power to step up the exploration for added reserves of oil and gas. I emphasize this in the context of recent marked reductions in exploratory drilling. Reduced drilling will lower the levels of proven reserves, disrupt our drilling industry and lead to even more reliance of imports of fossil fuels.

Inflation, offshore exploration and deeper onshore drilling have added greatly to the costs and risks of discovering new reserves. When energy prices are high and rising, operators tend to increase their drilling activity. When prices fall, drilling declines. We are now experiencing a sharp fall off in drilling. Reduced tax incentives could just about bring a cessation of exploratory drilling, expecially for high cost reserves.

Natural gas has special problems. For years and years gas was discovered largely as a by-product of the search for oil. Very low gas prices and the necessary access to pipelines tended to limit exploration for gas. In recent years the rise in the price of gas has resulted in substantially more gas drilling programs and in the discovery of sizable new gas reserves. After many years of declines in the ratio of total proven reserves to annual consumption, new reserve discoveries exceeded current levels of consumption in 1979 and 1981. The recent sharp drop in drilling for new gas reserves in certain to initiate another downtrend in the reserve-consumption ratio.

Drilling for new deep gas fields has dropped off precipitously because of the severe recession, high drilling costs, and a current surplus of available gas. Gas is becoming directly competitive with oil, especially among industrial and utility users of gas. The most favorable prospects for large gas reserves are in deeper strata than was generally true in the past, and that means higher costs for new gas. But it is not only deep gas that has become more costly. All new gas will be far more expensive than the old gas which it must replace over time.

The amount of exploration for new reserves increased substantially when prices for new gas, especially deep gas, were freed of any price controls. The higher costs and risks associated with all new reserves were manageable as long as gas prices covered total costs and were appropriately related to risks. When the price of old gas was controlled and when there was a strong and rising demand for natural gas, exploration for new reserves continued at a vigorous pace because the high priced new gas could be averaged in with low cost old gas. The resulting averaged price was relatively competitive with oil for industrial and utility uses. But that is becoming less and less true as old gas prices have been rising substantially.

In the past year or two, a number of factors have converged which have adversely affected the cost-benefit picture for new gas exploration. The United States has been suffering from the deepest recession since the Great Depression of the 1930s. Industrial demand for energy has fallen. It is not just the slowdown in the demand for natural gas that has precipitated this sharp drop in drilling for new reserves of gas; it is also a result of the market change in the price of oil. As petroleum prices softened and average gas prices moved up toward parity with oil on a Btu equivalent basis, the demand for gas was adversely affected. For the first time, some industrial and utility users of natural gas have been shifting back to oil because oil has become more favorably priced relative to gas in parts of the country for industrial and utility purposes. The magnitudes of the shifts are uncertain but pipelines have indicated serious concern about this matter.

The situation has been further aggravated by strong pressures from gas consumers and regulatory bodies on pipelines and other purchasers at the wellhead to halt purchases of costly new gas from deep sources. As a matter of fact, it has been proposed that long-term contracts for this new high cost gas should be abrogated summarily. Such a proposal is unique in the United States in peacetime. The Administration has seriously proposed legislation calling for the breaking of bona fide contracts. Gas producers have been renegotiating gas prices with pipelines and direct purchasers, but the situation is hardly an environment conducive to further pursuit of new gas reserves.

At long last, it now appears as though the misguided emphasis on incremental pricing in the sales of natural gas may be phased out. Only high priced gas was to be made available to industries and utilities when gas was in short supply. Any further tendencies to resort to carrying out incremental pricing policies would add greatly to the economic barriers to exploring for new gas.

These diverse and interrelated factors are not only discouraging to new drilling activities but also are certainly complex. The answers will not be found in simplistic solutions. Yet much of the debate going on with respect to natural gas prices and markets, as well as drilling, is geared to finding simple answers, which in fact may aggravate rather than ameliorate present conditions. What is needed now and for some years ahead are greater rather than lesser incentives to encourage exploratory drilling for new oil and gas reserves.

Given the general energy posture of the United States, it is highly important that we know as much as possible about gas reserves in this country. This can only be determined reliably by continued drilling for new reserves. Past data and past relationships are not going to provide the kinds of guidance needed to have reliable bases for measuring levels of potential gas reserves in this country.

The degree to which we can look to domestic and nearby (Canada and Mexico) natural gas as a significant substituted for imported oil will depend on prospective reserves of natural gas in the United States and on polciy decisions concerning short-term versus long-term benefits which this highly desirable source of energy can contribute to the nation. Certainly for at least the short-term, evidence of large gas reserves would be meaningful in formulating energy policies and in national security planning. But, it cannot be emphasized too strongly that drilling is an essential element in discovering and quantifying new reserves. The recent optimism about the prospects for larger gas reserves resulted in considerable measure because the greater and more costly drilling in recent years proved that more reserves could be found and the technological knowledge was enhanced in the process.

It cannot be assumed that natural gas reserves will be sufficient to eliminate or greatly reduce reliance on oil imports for an extended period of time. But certainly more gas usage could have important economic and security advantages for the United States. What is most important is the need for knowledge on which sound energy policies can be based. Unless we have reliable indications of potential as well as proven gas reserves—and the more we drill, the more reliable the estimates of potential reserves—the more difficult it is to formulate longer run energy policies, such as the role which natural gas should play in our society, not only for the balance of this century, but also well into the 21st century.

If large reserves of gas are proven, it is still questionable whether it would be in the national interest to fully exploit these reserves over a limited number of years in order to reduce reliance on oil imports. The need for gas well beyond the beginning of the 21st century ought to be taken into consideration. We must consider whether its qualities are sufficiently attractive and important to warrant spreading those reserves out over a longer period than would be likely if high priorities were given to the immediate increased use of gas. It would be conforting to be faced with such an issue. There certainly is an important need for more drilling to find and prove new oil and gas reserves.

A study is being made by Robert R. Nathan Associates, Inc. for Dyco Petroleum Corporation dealing with some of the issues I have presented. We know that investment in exploratory drilling for natural gas is on the decline. Unless some added incentive programs emerge soon or supportive policies are adopted that will give greater encouragement to exploratory drilling, we will have less and less drilling and we surely are going to know less and less about the potentials of natural gas reserves, a highly valuable resource.

Even with present tax incentives, it is going to be difficult to get investors to come forth with money for costly drilling when the market prospects for the sale of newly discovered gas in the short term are not favorable. These prospects will improve with substantial economic recovery, but for the time being the soft gas market and lower oil prices relative to previous peak prices will be deterrents to investors and drillers. Not only will that harm efforts to decrease our reliance on oil imports, but it also will mean fewer jobs and less investment at a time when the nation is suffering from high unemployment and low capital formation.

It is fair to conclude that under present circumstances this country is in for a continued and substantial further reduction in exploratory drilling for natural gas and oil. If the present tax incentives were reduced, exploratory drilling, at least for deep gas, would almost certainly dry up. It is far from certain that if the situation were reversed in the next three to five years, drilling would again increase immediately and substantially. When risks are high and adverse developments might be expected to recur, as they have in the last year or two with respect to gas drilling, the drilling industry may not be in a position to expand its operations speedily in response to national needs and investors may well be hesitant to participate again in new drilling programs. The nation's economic and security needs call for sound plans and policies both to reduce over time our dependence on oil imports and to be assured that security requirements will be met promptly and fully.

Mr. PICKLE. Mr. Dyer, do you want to make any concluding statement?

Mr. DYER. Yes, I would. My testimony will focus primarily on exploratory drilling, which Mr. Nathan has covered with respect to risk. Independents bring many investors into partnership arrangements for participation in drilling programs. In the past 5 years, 1977 to 1981, over $16 billion was invested in oil and gas through these partnership arrangements.

Since 1971, Dyco alone has been responsible for investments totaling over $300 million. We have had almost 20,000 limited partners in these programs, and most of these investors have participated in several programs, some continuously for as much as 10 years.

In essence a drilling program, for those not familiar, is a proposal made to prospective public investors offering them opportunities to invest in a series of exploratory drilling efforts to discover and develop new oil and gas reserves. Our company shares the risk with the limited partners by investing an amount equal to 30 percent of the total investment.

Because of the risky nature of the drilling, we make it clear in our prospectus that the program is intended only for those with a net worth in excess of $225,000 exclusive of home and automobiles, and taxable incomes of at least $60,000 a year.

Our purpose for initiating the Robert Nathan study was to determine whether or not we would be competitive in the future in trying to raise risk capital as we have in the past. Robert Nathan Associates analyzed the rates of return on our various programs. They studied 16 programs undertaken from 1971 through 1977. The results include the income received by our partners through 1982, plus the projected revenues yet to come.

Under those 16 programs, the average return is projected to be $4.2 per dollar invested. The very best program will yield over $23 for every dollar invested. The four least successful programs will return less than $2 for each dollar invested.

These results take into account the benefits of oil tax incentives and they also assume that investors earned enough income so that they were subject to the very top taxable rate of 70 percent through 1981, and 50 percent thereafter. Over the lifetime of each program, the annual rate of return varied from a peak of 55 percent in the most successful program to under 8 percent for the least successful program.

When these 16 programs are ranked by rates of return, the median program shows an annual rate of return of 20 percent.

That means half of the programs have done better than that rate, and half not as well. We believe these rates are based on finding costs that are in the top 25 percentile of the industry including independents and major companies.

The Nathan firm also analyzed the impact on rate of return of eliminating tax incentives. For the median program, the elimination of percentage depletion would reduce the return from 20 percent to 10 percent. If the intangible cost provisions were eliminated, the return would drop from 20 percent to 12 percent. If both of these incentives were terminated, the rate of return of this median program would drop to less than 4 percent.

These results point up the fact that the present tax incentives have been essential to attract investors even at a time when oil prices and markets for gas were highly favorable. Given the present conditions of a recession, lower oil prices, a soft demand for gas, high costs of exploring for new gas reserve, and scheduled decontrol of prices on most old gas, the inevitable conclusion is that reducing tax incentives would bring further severe declines in already depressed exploratory drilling operations.

I submit that liberalization for the tax provisions would be more appropriate. Thank you.

[The prepared statement follows:]

STATEMENT OF JAYE F. DYER, PRESIDENT, OIL INVESTMENT INSTITUTE

My name is Jaye F. Dyer and my title is President of Dyco Petroleum Corporation (Dyco), which is listed on the New York Stock Exchange. Also, I am the President of the Oil Investment Institute (OII), made up of more than two dozen independent oil and gas exploration companies. I am a geologist by training and have been active in the oil and gas industry for 32 years, of which 25 years have been devoted to the programming of drilling and developing activities. I have worked with major companies in the industry as well as independents.

I appreciate the opportunity to appear before the Oversight Subcommittee as a spokesman for Dyco and OII. Just to put my comments into proper perspective, let me say a few words about the oil and gas industry and independent operators to be followed by a description of drilling programs and how they work.

In the five years 1977 through 1981, nearly $93 billion was spent by the petroleum industry for onshore drilling and completion of new oil and gas wells in the United States. that is an average investment of over $18 billion per year to discover and develop oil and gas fields. It represents a major contribution of the oil and gas industry to the economic well-being and security of our nation. These large investments added nearly 11 billion barrels of oil and almost 83 trillion cubic feet of natural gas to our known reserves. but for these large investments the United States would be sliding ever more rapidly and more deeply into dependency on oil imports.

The petroleum industry is comprised of many segments ranging from wildcat drilling and development of known fields to transportation, processing and distribution of oil and gas, all of which face risks and problems. I do not intend to discuss all these segments because the purpose of my testimony is to focus primarily on exploratory drilling, which is a principal though not exclusive function of the independent operators. Most wildcat drilling is undertaken by independents. Their high risks are apparent from the fact that an average of more than eight out of ten exploratory drillings result in dry holes or very minor producers. Special incentives continue to be essential in an industry where the risks are so great and where the industry plays such a critical role in the nation's economy.

Few independents have the means to engage in sizable drilling programs without partners. Therefore, they seek investors who are willing to participate as partners in these oil and gas drilling ventures. These partners are individuals with asset and income levels sufficient to risk their money in these ventures. They are interested in the opportunity available to share in programs which involve drilling a considerable number of wells and thereby spreading their risks. They understand the risks and the possible rewards. They are prepared to take chances in the expectation that there will be a producing wells which will yield attractive returns. The combination of organizers and operators of drilling programs and of outside investors is in the best tradition of our enterprise system. It has been an important factor in America's economic and energy growth, made possible through increased oil and gas availability and use.

In the five year period 1977–81, over $16 billion was invested through partnership arrangements, resulting in a new reserves of 1.8 billion barrels of oil and 14 trillion cubic feet of natural gas. That five-year total of new proven petroleum reserves through partnership programs equals more oil than the United States imported in 1982. Independent operators and their partners are desirous of continuing their exploration for oil and gas, but they can do so only if the economic enviroment provides favorable profit prospects for both the operators and their non-operating investors.

At the present time Dyco is the largest organizer and operator of publicly offered drilling programs for the exploration and development of oil and gas resources. Our company's initial drilling program was undertaken in 1971 and, through 1982, we financed and operated a total of 26 such programs. Two programs are scheduled for 1983.

Against this general background I would now like to discuss more specifically how my company functions. Many members of OII operate in a similar manner.

I want to make clear at the very beginning what a drilling program is. It is a proposal made to prospective investors offering them opportunities to invest funds in a series of exploratory drilling efforts designed to discover and develop largely new reserves. Each program has been registered with the Securities and Exchange Commission. The investors are solicited only through the distribution of a Prospectus for each program. I am submitting a copy of the latest Prospectus which covers the initial drilling program for the year 1983, designated as 1983-1.[1]

We have closed the 1983-1 program with subscriptions totaling $38 million as compared with the total offering of $60 million. The amount invested in each of the 26 Dyco programs is shown in the Prospectus on page 21, adding up to nearly $300 million for the period 1971 through 1982. The securities sold in the first five years (1971-75) totaled just under $20 million, whereas in 1982 along $90 million was invested. Total subscribed investments in all the years of 1971 through 1979 were only slightly over the 1982 aggregate of $90 million. The four programs in just 1981 and 1982 totaled more than was invested in all the previous 22 Dyco programs. The total number of individual investors in all of Dyco's 26 programs is nearly 20,000 and many of these individuals have participate in more than one program.

We state clearly in the Prospectus that investment in a drilling program is intended only for those whose net worth is at least $225,000, exclusive of home, furnishings and automobiles and with taxable incomes of at leat $60,000 per year. We emphasize the risky nature of the undertaking because in exploratory drilling one can never be sure of having a producing well until the drilling operation has been completed. We have made some progress in the technology of site selection for exploratory drilling, but the overwhelming portion of dry holes reveals the high risks involved in this industry.

Dyco has been able to increase its number of investors and total subscriptions substantially because of its success in achieving reasonably attractive rates of return in many of its programs and because of its good relations with its partners. Dyco has been meticulous in fulfilling all of the registration requirements, in keeping its investors fully and objectively informed, in mobilizing the best technical talents in this field, in sharing costs of productive operations with its investors, in limiting mandatory assessments, in providing for repurchase of participant's units under certain conditions, and, above all, in helping develop comprehensive and solid understanding of the nature of the risks and rewards involved so that the investors can make their decisions based on full information. Dyco never tried to stimulate investor participation in its drilling programs as tax avoidance schemes. These programs have always been described as bearing considerable risks along with tax incentives designed to encourage the investors to assume those risks.

About the middle of 1982 we became concerned about the impact of the recession on the natural gas industry. The demand for energy was weaker and an oil "glut" became evident. Gas prices had risen to a point where competition between gas and oil evolved. There were signs of less demand for drilling rigs. We decided late in 1982 to analyze all these developments more fully and we arranged for a study of our operations, of the economic factors that have been evolving in our economy, and the impacts of these factors on the gas industry. This study, now nearing completion, was undertaken by Robert R. Nathan Associates, Inc. (RRNA).

One of the investigations undertaken by RRNA was to analyze the rates of return on our various programs. An analysis has been completed of 16 programs initiated in the years 1971 through 1977. The analysis stopped with the 1977 programs because the rates of return take into account not only costs and revenues in the years that have elapsed since the program was initiated, but also future production as projected by experts, and the translation of that future production into corresponding revenues. It takes some time before it is possible to arrive at reasonably reliable estimates of future production from successful producing wells. RRNA felt that the programs undertaken more recently than 1977 were not sufficiently mature to provide a sound basis for developing rates of return over the lifetime of the productive wells.

For those 16 programs, $89.5 million of subscriptions and assessments were invested by partners. Cumulative total receipts, including cash distributions through 1982, estimated future income and other assets aggregated $375.8 million. This resulted in the receipt of $4.2 per dollar invested. The most successful program (1972-1) is scheduled to pay back $23.4 per dollar invested and the next best will return $5.9 per dollar invested. On the other hand, four programs will provide total receipts of less than two dollars per dollar invested.

To determine the effective annual rate of return over the lifetime of a program it is important to take account of tax incentives and of the time factor between the dates of investing and the dates of cash received by the investors. With respect to tax benefits, the investor was assumed to have sufficiently large taxable income so that the maximum tax bracket rate of 70 percent would apply through 1981 and the maximum of 50 percent thereafter, in accordance with the ceiling rates provided in our tax laws. Taxes on capital gains were computed at the maximum rate applicable in each year. Benefits of percentage depletion were computed under the small producer—or most favorable—exemption. Allowed intangible deductions were also valued at the maximum tax bracket rate.

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[1] Editor's note: A description the corporation's 1983 oil and gas programs, submitted to the subcommittee, has been retained in the files.

The results per program indicate annual rates of return, under these most favorable assumptions, ranging all the way from the highest rate of return of 55 percent in the 1972-1 program to the lowest rate of less than 8 percent in a 1975 program. The second highest was 40 percent and the third highest was 32 percent. The second lowest rate was 10 percent and the third lowest was 12 percent. Again, the variations are very large, revealing the high degrees of risk in this field of activity.

In arriving at the base on which the rate of return is determined, initial subscriptions and assessments are reduced by the amounts of tax benefits enjoyed by the investor because of full expensing of intangible drilling costs. Revenues include the tax benefits of percent depletion from sales of oil and gas. Therefore, when we refer to rates of return we are taking into account all the benefits derived from tax incentives.

In addition to analyzing rates of return under prevailing tax provisions, RRNA also calculated what the rates of return would have been had the tax laws been changed by eliminating percent depletion and by substituting five year depreciation instead of current expensing of intangible drilling costs.

For the median program, namely, the one which showed the middle results among the 16 programs ranked by rate of return, the annual rate of return over the lifetime of the program was found to be 20.4 percent. But, if the intangible cost provisions were eliminated and replaced by a five year amortization schedule, the rate of return would be only 12.1 percent. If the percentage depletion were eliminated, the return would drop from 20.4 to 10.2 percent. If both of these tax inducements were eliminated then the drop would be to 3.7 percent.

Given the risk factors that prevail in the drilling for oil and gas, it is clear that such tax changes would have had a disastrous impact on exploratory drilling. There are many alternative investments which are far more attractive than such returns as are indicated above.

For the lowest of the 16 analyzed drilling programs the rate of return under present tax laws is 7.9 percent. Without percentage depletion it would be 6.2 percent, but without the expensing of intangible costs it would be 1.8 percent. Without both tax incentives it would be under one-tenth of one percent. For the most successful program, the projected 55 percent rate of return would be reduced to 24.8 percent if the two tax incentives were eliminated. That is still a rather attractive return, but it must be emphasized that it is the very best of the 16 programs. The next best of the 16 programs, which now shows a 39.6 percent return, would fall into the 12 percent range without the two tax incentives.

These results point up the fact that the present tax incentives have been essential at a time when oil prices and markets for gas were highly favorable. Given lower oil prices, a soft demand for gas relative to supply, the high cost of exploration and exploitation of gas reserves and scheduled decontrol of prices on most "old" gas, the inevitable conclusion is that reducing tax incentives would bring further severe declines in exploratory drilling operations. What is needed is a liberalization of such tax provisions rather than any decrease in tax incentives.

In view of the inevitable relationship between prospective rewards to the investors and their perceived and real risks, the organizers and operators of drilling programs must be constantly sensitive to changes in all of the cost and benefit factors which will influence the prospective investor in his decisions. Any operator engaged in drilling programs must understand that minimizing risk and maximizing return relative to risk will determine whether or not the operator will enjoy a continuing and successful relationship with existing and prospective investors. Continuity importantly depends upon performance in most kinds of enterprises, but it is especially true where one is dealing with people who are putting their savings into the hands of those who have to make a wide range of important decisions in an inevitably risky industry.

Not only must the operator of drilling programs seek the best possible technical competence in selecting individual drilling projects, but he must also minimize cost in drilling and completing wells and in selling the gas as soon as possible. The rate of return analysis inherently takes into account the time element and therefore the longer the time interval between date of investment and date of initial revenues, the lower will be the rate of return.

The operator must be as knowledgeable as possible on government policies as they affect energy and also must be aware of international developments in the energy field. Changes in prices, in demand-supply relationships, in competition between different sources of energy, in nation-to-nation relationships which influence supplies of and markets for fuels, in environmental considerations, and the like are all critical elements that affect the results of drilling programs. The Prospectus given to each investor for each program must be forthright in discussing these factors and emphasizing the risks associated with the drilling program and the economic and policy environments within which the program will be implemented. At this time those environments are unfavorable for independent operators, but it is in the national interest that exploratory drilling programs continue in substantial degree.

My associates and I take great pride in the performance of Dyco. We have been organizing and operating drilling programs for a dozen years and we have enjoyed steady growth. We have had the benefit of repeated participation in program after program by satisfied investors. We have been diligent in developing and operating our drilling programs. Yet, we fully recognize that our role is importantly influenced by forces beyond our own control. One of these important factors is the degree to which our government recognizes the need for incentives in this risky area.

We recognize the risks for investors, especially individual investors, inherent in government policies and we make our investors aware of those risks. We very much need stability in government policies if we are to make contributions toward limiting America's dependency on oil imports. I hope sincerely that government policies will realistically adjust and adapt incentive programs, to insure that substantial drilling programs can and will continue for the foreseeable future because continued discoveries of new reserves are an important ingredient in achieving the nation's energy objectives. They will not continue at essential levels if incentives to the individual investor are not commensurate with his risks. Buying shares in large oil and gas corporations is not nearly as risk-oriented as direct investment in drilling programs.

Now, a final word about OII, which was organized to do away with many of the problems earlier associated with attracting individual investor participation in drilling programs. We joined together to create an association of independent drillers offering public programs because we were concerned that this investment concept might be destroyed by the actions of a few promoters who seemed more dedicated to selling tax shelters than building exploration companies. The organization published a statement of business standards and voted to require all members to adhere to the standards. Some members dropped out because they did not want to be bound by the guidelines, and I believe those companies are no longer in the public program business. The OII worked closely with the Securities and Exchange Commission to draft a proposed regulatory statute for public drilling programs. By 1972, the OII had worked with the North American Securities Administrators Association (state securities commissioners) in formulating and adopting a firm set of guidelines to govern and standardize regulation of publicly offered oil programs. I strongly believe that the performance of OII and its members has had much to do with the growth and success of strong competitive exploration companies that year in and year out have contributed constructively to our economy.

I sincerely hope that the testimony we have presented to this Subcommittee will be helpful to you in your deliberations and that you will agree that present and foreseeable conditions call for more attractive tax incentives rather than curtailed inducements for this important industry.

Mr. PICKLE. Thank you, Mr. Dyer. I certainly appreciate your statement and yours, Mr. Nathan, which complements what Mr. Dyer has said.

Mr. Thomas, do you have questions of the panel?

Mr. THOMAS. Just a couple; one to assist me in reading the materials.

Mr. Smith, on your Z-Score bankruptcy model. What is Roman numeral VII column in this sheet that was passed out to me, Mr. Smith?

Mr. SMITH. The Z-Score is a multivariate discriminate analysis that takes financial ratios and applies a coefficient to those.

Mr. THOMAS. I understand that, but give me the parameters on the results on the Z-Score. I am looking at one company that is a 0.45.

**Mr. Smith.** Right. Well, while it is not 100 percent successful in prediction, the cutoff point is 2.5, companies that are below a 2.5 Z-Score often run the risk of financial failure.

**Mr. Thomas.** Is it something like the Richter scale where it is geometric as you move away from the 2.5 or is it linear?

**Mr. Smith.** There is one significant factor that has to be looked at in that group, and that is the Z-Score was based on valuation of manufacturing companies. It does not necessarily correlate with oil companies.

However, I have run this screen now for about 1 year, and the companies in the very bottom of the list—including a number of oil service companies—have gone bankrupt, and are now in chapter 11.

**Mr. Thomas.** We can assume those in the minus category are certainly in jeopardy?

**Mr. Smith.** Right. It does point out that there are very, very many companies in difficulty; and it is a small survey.

**Mr. Thomas.** Mr. Dyer, Mr. Nathan, and if you choose to, Mr. McKenna, the two of you, Mr. Nathan and Mr. Dyer both ended your testimony by indicating that the incentives ought to go up, if anything. Do you want to take a minute and talk about what you think ought to be done rather than the general statement, the incentives ought to be increased? In what way for which group and why?

**Mr. Dyer.** I can only speak for the independent segment. I cannot speak for the major companies. I have never been terribly favorable toward discriminatory tax positions between the industry, but nonetheless——

**Mr. Thomas.** Is what we have on the books now discriminatory?

**Mr. Smith.** I think it is somewhat discriminatory against the major companies. But I do feel this. That the amount of exploratory drilling that we can do is a function of all the economic factors that come into play, including the tax incentives.

We don't see anything on the price horizon that is going to be terribly encouraging over the next 2 years nor in the demand area. Oil companies can do certain things in cost reduction, and drilling costs are coming down very rapidly and companies are becoming more efficient. But, it leaves the third item and that is tax incentives.

If we are going to accelerate our rate of exploration, particularly in the natural gas area, where we are drilling deeper and deeper all the time, it seems to me that we have got to provide the incentives someplace, and I believe it must come from tax.

**Mr. Thomas.** You also indicated, and I believe Mr. McKenna you mentioned this, there is a psychology involved of course in terms of what this Congress may or may not do in regard to the present tax law. Would it be worth anything even in the short run if we were to go through these proceedings and arrive at the determination that nothing ought to be done? It seems to me in the context in which we are dealing that is a minor positive, anyway.

**Mr. McKenna.** I would agree. I think that uncertainty is the key issue here, and to the extent that we are fiddling with the tax rules it creates an uncertainty.

Mr. **Thomas**. And that to the degree we can examine it and say that we are satisfied with what we have got, that maybe an incentive for people to go back into the oil and gas, or are the risks so great now that it is going to have to take some kind of a positive substantive move rather than a psychological move?

Mr. **Smith**. I think that elimination of uncertainty would be a key factor in getting people back into the oil and gas business.

Mr. **Nathan**. Can I just add one thing, Congressman Thomas. You know we have a percentage depletion of 27.5 percent, and that we reduced some years back, and it always seemed to me strangely perverse to have a very high incentive at the time of America's considerable degree of independency of energy resources, and at a time when we really ought to be probing and fiddling and searching and proving up what our reserves are, we have turned around and cut the incentive.

I think, of course, obviously first of all to prevent a reduction at the time is absolutely essential, and to create added uncertainties about the possibilities of it would be disastrous, but I honestly believe if we are going to really seek to minimize our dependency and to try to depend primarily on our own resources at a time of national or international stability and the like, what we really ought to consider is going back to the 27.5 percentage depletion to try and get as much reliance on domestic resources as possible.

Mr. **Thomas**. Do any of you feel comfortable in commenting on the investment opportunities in the alternate energy area? Is this an attractive area? Is this attracting capital? Are there tax incentives in this area that are attracting capital, is anyone aware?

Mr. **Smith**. I have followed the activities of some of the major oil companies, including Exxon and others, and the general belief is that energy price escalation in the future will not be sufficient enough to justify the enormous capital investments required here. Conventional energy sources will be emphasized, at least for the next few years. Without some sort of significant protection on the price side as well as other tax incentive these projects cannot go ahead on an economic basis.

Mr. **Thomas**. Just let me make a comment, Mr. Chairman. My district, as I have indicated a number of times yesterday, is a significant producer of oil and gas. It also has commercial capabilities for geothermal. It has one of the premier areas in the world for wind energy in the Tehachapee area and I have visited those wind parks. I also have in my district the first large scale photovoltaic plant, and just outside my district in Barstow, we have the reflective plants; so we really are, except for ocean experimentations either with the differential temperature in the water or the waves, pretty much at the cutting edge of the alternate energy activities here in the United States.

I am not talking about fellows in the back yard. I am talking about relatively large corporate investment, one-half a million dollars per wind machine. We have got 400 of them now, and we are continuing to try to perfect the designs because they simply aren't economically feasible.

All of the folks involved in these activities tell me that without the tax credits in some instances or incentives in others, they simply would not be in the business and it is going to take a tremendous amount of research to get us away from gas and oil powering America, and all of the comments that I have heard over the last several days virtually all of the comments, except for Alice Rivlin, who wants a neutral tax policy, have indicated that there has to be a strong working relationship between independents and the corporations.

I want to thank you, gentlemen, for the financial comments that you have made.

Thank you, Mr. Chairman.

Mr. PICKLE. Thank you, Mr. Thomas.

Gentlemen, you did not paint a very rosy picture for us on the track record in the last 18 months to 2 years, or the investment picture as you see it in the immediate days ahead. I am almost hesitant to ask questions about the number of bankruptcies, but it does concern me.

We today have heard that in the southern district of Texas alone we had 165 bankruptcies this last year. I assume that proportionately the same rate would exist in other parts of the country. That is a large number of bankruptcies; and I have to assume they are the independents or investors in independents' operations. What has caused these bankruptcies? Why have we had so many of them?

Mr. SMITH. Again, I think part of it is just the cyclical nature of the oil industry; that there were excesses in the business during 1979 through 1981. Companies that were in startup phase probably should not have been in the business, and some of that is a result of natural consolidation.

Mr. THOMAS. What do you mean by excessive now?

Mr. SMITH. Companies that did not really base their economic investments on the probability of success. There were just too many companies getting into the business because things were going well, and the price of oil was going to keep going up.

Mr. THOMAS. Are you saying that a lot of them made investments that the oil picture was going to get better and better instead of oil staying at $35; it was going to go up to $150 a barrel?

Mr. SMITH Yes.

Mr. THOMAS. Now having made those kinds of assumptions, the error then if there is an error, the error then is not the operation of our tax code or the differential bracket, but the fact that bankers and oil and gas people just punched too deeply and made poor judgment in some cases; is that correct?

Mr. SMITH. I am sure there was some poor judgment, but you must remember that such investments were viewed as something that should take place in the national interest. Decontrol of oil stimulated companies to get into the business. The assumptions changed, though they were consensus assumptions across the world. Everyone thought OPEC would raise prices forever.

Mr. THOMAS. Obviously that has happened, but the fact remains that it must be that some poor judgments were made, and we have got to distinguish that from what we are concerned with here, with respect to the tax laws. We had a lot of oil and gas people who are traditionally plungers anyway, and they made poor decisions, and several banks have done the same thing. We have to admit that, don't we?

Mr. **Smith**. I would agree. There are many excesses and they are being corrected now. The problem, of course, is that changes now would exacerbate the problem. We would have many more bankruptcies than would occur otherwise.

Mr. **Thomas**. Poor judgment. What else has caused our bankruptcies?

Mr. **Nathan**. I would just add that the recession really was a significant fator. The recession has resulted in a slowdown in aggregating demand for energy. It is obvious. You see it in the electrics, you see it in oil, you see it in coal. The result is that the risks at a given level of economic activity in the economy may be justified and may be good judgment, and some will always fail, but when you do have a combination of a recession on the one hand and then a lot of I think cheating among the companies in OPEC which resulted in increased production and a reduction in prices, that shifted the margins, that shifted the risk factors, and I think anybody who speculated widely on the assumption that OPEC was never going to have a reduction in price, there would never be a recession, did take the risk; but the problem is now that those failures are having a very significant effect on the willingness of people to invest in oil and gas. You see that in the drop in drilling.

Mr. **Thomas**. In that connection, Mr. Nathan, and since you have made that statement and since Mr. Dyer has given us some disturbing figures, I am asking myself why wouldn't investors be slacking off now or hesitating to get into these operations, at a time when the tax structure generally is favorable to you. At least we have attempted to make it as favorable as possible, in the hope that we could encourage production.

The examination that you gave us here, Mr. Dyer, you showed on page 7, you get to speak about the potential tax benefits, you give an example here, if you made an investment of two units of $5,000 each, you show what was invested there, plus the add-on of the assessment, assuming a 15-percent assessment.

Mr. **Dyer**. Correct.

Mr. **Thomas**. You showed a cash investment of $11,500, and yet the after-tax investment cost was $5,750. In other words, you got nearly half of it back. That is a pretty good enticement. It is a good tax advantage that the tax structure offers.

My first impression is that you don't do so bad. You put up $11,500 and you can write off $5,750. My question is, what concerns me is in spite of that incentive, the investors are not investing. Now why is that?

Mr. **Dyer**. I think their perception is that the economics of the oil and gas business have changed dramatically, and that maybe the tax incentive is insufficient now to take the risk. I think that is the perception. There was a real——

Mr. **Thomas**. That is a pretty good incentive.

Mr. **Dyer**. It certainly is, and we are anxious to retain it. We think it is necessary to retain it.

Mr. **McKenna**. Mr. Chairman, you mentioned the linkage, what has happened, why have these bankruptcies occurred, and I just wanted to make a point that we tried to do some Monday morning quarterbacking on that in Houston where I live, and we came out with the three important qualities right now for an independent oil company, and these are cash flow, cash flow and cash flow.

You can't change what has already occurred—you know that we are trying to go back and figure out what happened. We are trying to help, and the only way we can help is to bring capital back into these companies, to replace the deteriorated cash flow.

To the extent that the tax incentives or the tax rules are changed, this is going to really hinder our ability to raise capital for this industry.

Mr. **Pickle**. You indicated that you need cash flow, cash flow, cash flow. Mr. Nathan said what we need is investment, investment, investment, or who was it this morning that made that statement? We tried to make an incentive there for investors, and whether you want to consider it liberal or questionable, the fact of the matter is that we still do not have enough investment.

It seems to me, too, that we must admit that within the last year or two we have assumed too much in the oil and gas industry. We took for granted that OPEC would never make a price cut, that prices were just going to go up and up, but they did reach a point where we cut our consumption.

We have got to put salt and pepper on our own judgment in the oil and gas industry and say we have made mistakes. In spite of the fact that the oil and gas industry has good incentives, people are still reluctant to invest because, I assume, there is so much uncertainty in the whole field now that they just prefer to invest somewhere else.

Treasury testified yesterday that ARCS gives a better return than oil and gas incentives, so I think that is a factor, too. So while it is not a good picture, I think we have got to recognize that we have also made some mistakes in judgment. We had better recognize that fact.

Mr. Anthony?

Mr. **Anthony**. Mr. Chairman, I understand I don't have to ask a question, but I am really curious on one basic point as a followup to what you asked on investment. There are three amounts of tax shelter incentives in here to encourage investors to go into the market. Let's say I applied, qualified, and I am going to buy two units at $5,000 each.

I want you to tell me what my downside risk is, if you go out there, take my money and drill. As it turns out, you come up with one of those old dusty things that they have been talking about, and then you write me a Dear John letter. In this case it will be a Dear Beryl letter and say, 'Dear Beryl.'

Mr. **Pickle**. Is that spelled Barrel?

Mr. **Anthony**. Since the chairman is married to a Beryl, he knows how to spell it. But the letter would go something like: 'Dear Beryl, we are so sorry to break the sad news to you, but after having drilled this well to so many feet, we have logged it and our geologists have concluded that we have hit a dry hole and we are abandoning it, but we encourage you to take another look at a unit that we have coming on stream next week. We know that you would want to purchase into it.'

What is my downside risk here?

Mr. **Dyer**. Your downside risk is to lose all your money.

Mr. **Anthony**. I now lose all $11,500?

Mr. **Dyer**. Yes. I consider all of that lost. You get to deduct that loss as a capital loss, but nonetheless you have lost the opportunity to invest that money someplace else.

Mr. **Anthony**. So even with the substantial tax incentives that we have placed in the code to encourage people to form partnerships and to explore and develop new reserves, there are substantial downside risks, if you are not successful.

In other words, I can lose the corpus with which I started.

Mr. **Dyer**. Yes, sir, you certainly may.

Mr. **Anthony**. Are these downside risks, coupled with costs, causing the lack of investors to come forward?

Mr. **Dyer**. Yes. I think so. There are really strong incentives to invest when the price rises very rapidly, and especially natural gas following the NGPA. A little blue sky from all of this was that it did provide natural gas reserves equal to our consumption for the first time in 14 years.

Now a lot of that price incentive is lost, and if we were to heap a loss in tax incentives on top of price, then our drilling will decline to disastrous levels.

Mr. **Anthony**. If I understand you correctly, you are really saying that price and future prices have a more dominant role than the tax breaks themselves; because as Mr. Pickle said, if anybody were to look at all of those tax breaks and compared them with other investments, it looks like they would be knocking your door down every day. I don't buy the argument that just because we are holding hearings and because there is some uncertainty on what may happen to the tax code that a number of investors are being driven away. If the profitability is there, the investors are going to be out there in great droves.

Mr. **Nathan**. If I could just add one word to what Mr. Dyer said, you know you do have a very major risk factor, as you pointed out yourself. You might drill a hole and it is dry. All that money is gone. You do have an offset by the intangibles being written off against other income, but you have still lost a very substantial amount of your investment.

Now sure if everything is favorable, the prices are favorable, the demand is there, there is a short supply relative to demand, the profitability prospects are more favorable, and therefore the incentive may not be as important, but when you move into a period as serious as it is now, where you add to that basic inherent risk in drilling, basic inherent risk, you add on to that the risk that is associated with the softening of price demand, you add on a risk that is an increase in drilling costs as a result of the inflation we have had, that you have to drill deeper to get reserves, and therefore you are putting up more money, then I think one begins to realize that profitability has to be very attractive, given those risks compared with other risks where you can get very good returns but you don't have nearly that degree of risk.

Mr. **Anthony**. Thank you.

I yield back to the chairman.

Mr. **Pickle**. Thank you, gentlemen for your testimony. We appreciate it very much.

The next panel consists of the National Association of Royalty Owners. Mr. Jim Stafford, Mr. Steve Nolan, Mr. Octavius Fisher, and Mrs. Marie Dunn.

Will those people please come forward and take a seat at the witness table?

Mr. Jim Stafford, executive director. He is accompanied by Mr. Steve Nolan, royalty owner from Chicago, Ill.; Mr. Octavius Fisher of Columbia, Md.; and Marie Dunn, certified tax practitioner, Fox, Okla.

Mr. Stafford, do you make the statement or do you all make statements?

## STATEMENT OF JAMES L. STAFFORD, EXECUTIVE DIRECTOR, NATIONAL ASSOCIATION OF ROYALTY OWNERS

Mr. **Stafford**. I will introduce them first and then make a summary statement.

Mr. **Pickle**. We will include your entire statement in the record.

Mr. **Stafford**. Thank you, sir.

The first witness, Mr. Chairman, will be Mr. Fisher.

Mr. **Pickle**. Mr. Stafford, before you proceed, let me remind the committee again we have seven other panels. We have a long day ahead, so I am going to ask each of you again to try to summarize in a 5-minute period, so that we might have the privilege of hearing everyone today.

Now go ahead, Mr. Stafford.

Mr. **Stafford**. The first witness we have is Mr. Octavius Fisher of Columbia, Md. He is retired and 84 years old, and he has interest in the East Texas oil field and I would like him to say a few words, please, Mr. Fisher.

## STATEMENT OF OCTAVIUS R. FISHER, ROYALTY OWNER, COLUMBIA, MD., ON BEHALF OF THE NATIONAL ASSOCIATION OF ROYALTY OWNERS

Mr. **Fisher**. Mr. Chairman, my name is Octavius Fisher and I live at 5973——

Mr. **Pickle**. Sir, will you pull that microphone closer to you or pull up your chair?

Mr. **Fisher**. I live in Columbia. I will be 85 in a couple of weeks. I am a veteran of World War I, a disabled veteran.

In 1935 or before that, my brother was a chemist with the Chemical Warfare Department during World War I, went to Texas, set up a laboratory and built a waxing plant. We cleaned out the oil pits of waste oil around the country. This oil had been burned off at night, years before. We brought it back to our unit, and we cracked that wax and made what we call a pit wax or a mineral wax. It was used in the carbon paper, fabrics and several other uses.

We sold a few cars of this mineral wax and did pretty well but had a difficult time in getting the waste oil from the various pits. Finally we had a strike at our little setup when we were paying labor $1 a day, and they wanted $1.50 a day. They sent us out of business.

My brother stayed on in Texas and married. I moved back to New York where my wife is from, and I worked for the city of New York in the police department for a while in the engineering bureau. I installed traffic lights throughout the five boroughs and barricades, anything pertaining to engineering for quite some time.

Then I retired. I moved to Columbia to be near our daughter, and I depend entirely upon my royalty income to supplement the social security. If I lost that income, I would be in a bad way.

My interest in the oil business has been over quite some time, and I pay seven different taxes in the State of Texas. I pay three taxes in the State of Maryland, and I pay three taxes where I own a small lot up in Pennsylvania. I pay mineral tax, school tax, production taxes, State taxes, income taxes, and windfall profit tax. In fact, just recently I received a check from one of the companies. My check was for $46 and some change, and the deduction from that check was $96 and some change.

I don't think that is consistent with the policies of the Internal Revenue Department or any department that has something to do with the taxes. That type of thing is ridiculous; to me it is.

The two-barrel extension did not exempt all of my royalty income from the windfall profits tax, but the third barrel would be adequate. Because leases in east Texas are given on fairly small tracts, I receive checks from several different companies on our approximately 130 acres. Some of these oil run stubs and checks of course on the withholding tax are rather high, according to the amount of money I receive.

I do my own taxes, and it can be very difficult. You have to be a Philadelphia lawyer to figure out some of these taxes that contain the various tiers of oil and the various other categories that they put these various oil runs in.

I don't mind paying my share of taxes, 60 to 70 percent of my take in taxes, Mr. Chairman, is a little high. I haven't got much longer to go. People who receive royalties from other things in life such as music or machine patents I don't think pay windfall profit tax. I feel as if I have been discriminated against in some form or measure that is not suitable at this time.

I have been trying to help out a family recently in Columbia who are in the same position, who own property in Texas, and who just cannot get along with that reduction of their windfall profit tax. I am opposed to the windfall profit tax because it was meant to punish the big oil companies, and only succeeded in putting a hardship on a lot of little people; widows and retired people like me.

Thank you, Mr. Chairman.

[The prepared statement follows:]

### STATEMENT OF OCTAVIUS R. FISHER

Mr. Chairman, members of the committee, I want to thank you for the opportunity to appear here today.

My name is Octavius R. Fisher and I live at 5973 Grand Banks Road in Columbia, Maryland. I am 84 years old, a World War I veteran, and a royalty owner.

In 1935 my brother, who was a chemist, went to East Texas and settled near Kilgore, in Rusk County. He set up a laboratory, and started what was called a "waxing plant." I joined him there, and we were in business together for several years. We built that plant our of discarded materials we found around the countryside.

Back in those days, the waste oil from an oil well flowed into open pits, and was burned off at night. We collected the residue from those pits, hauled it by truck to the plant, where we had erected a cracking unit, and extracted a hard substance called mineral wax. This mineral was was used for many purposes in manufacturing other products. They used it in carbon papers, I think in some fabrics, and several other items.

We sold a few tank cars of mineral wax, and did pretty well. But we had a difficult time getting the waste oil from the various pits, and finally had to close down the operation. But during that time we were able to buy some land and some mineral leases.

My brother stayed on in Texas, and I moved back to New York City, where my wife is from, and went to work for the New York City Police Department in the Engineering Bureau, installing traffic signals, barricades and lines. My retirement income is from Social Security, a vey small Police Department pension, disability compensation from the V.A. and my royalties.

When I retired, we moved to Columbia to be near our daughter, and we depend on our royalty income to supplement the pensions and Social Security. If I lost that income, we'd be in a bad way.

Our production is Tier I Oil, and is taxed at the highest rate—70 percent. We pay real estate, mineral, school land and gross production taxes to the State of Texas. We also pay income tax on what is left to the State of Maryland, Howard County, Maryland, and the federal government.

The two barrel exemption did not exempt all of my royalty income from the windfal profits tax, but the third barrel would cover all of it.

Because leases in East Texas are given on fairly small tracts—10 to 40 acres for the most part—I receive checks from several different companies on our approximately 130 acres. I've brought along some samples of run check stubs showing windfall profit tax withholding. (See Exhibit A). As you can see, on one check, $7.40 was withheld from $11.68. On others, one-third to one half was taken for windfall tax. The worst, though, was a case where $93.42 was held out for windfall tax, and I received only $46.14.

I do my own taxes, and it can be very difficult. You need to be a Philadelphia lawyer to figure these taxes out. A lot of time the IRS contradicts itself in the instructions, and my figures don't always agree with the oil companies.

I don't mind playing my share of taxes, but the windfall profits tax is unfair because it discriminates against people who have oil royalties. People who receive royalties from music, or machine patents, don't have to pay a windfall tax. I'd be much better off if my interests were in New York City real estate or rental property, instead of some wells that could be plugged tomorrow or put out of commission for several months by a workover operation.

Recently, I've been trying to help out a family in Columbia who have held on to some acreage in Jefferson County, Texas, by paying taxes on it for many years. Right now they're destitute. The mother is nearly senile and she, her daughter and grandaughter are on public assistance and in a bad way. Now it looks like they're going to get some production on that property, and the royalty they receive won't be a windfall, it will be a Godsend.

I'm opposed to the Windfall Profits Tax because it was meant to punish the big oil companies, and only succeeded in putting a hardship on a lot of little people, widows, and retired people like me.

Thank you, Mr. Chairman.

Mr. PICKLE. Thank you, Mr. Fisher.

Do the other witnesses have statements?

Mr. STAFFORD. Yes, sir.

The next is Mr. Steve Nolan, a retired steelworker, 43 years, Chicago, Ill., 71 years old.

## STATEMENT OF STEVE NOLAN, RETIRED STEELWORKER, AND ROYALTY OWNER, CHICAGO, ILL., ON BEHALF OF THE NATIONAL ASSOCIATION OF ROYALTY OWNERS

Mr. NOLAN. Mr. Chairman and members of the committee, my name is Steve Nolan. I am 71 years old, I live in Chicago, Ill., and I am a royalty owner.

For 43 years, I worked in the steel mills in southeast Chicago. I am retired now, and my wife, Berneice, and I live on income from social security, my pension and oil royalties from two producing wells in Edwards County, Ill.

My wife's parents bought their farm, about 250 miles from Chicago, in the early 1900's, and after her parents passed away, the farm was put up for auction. We bought 140 acres of that farm in November 1974. Shortly after we bought the land, it was leased by an oil company, and the two wells came in, in July 1975.

We own half of the minerals under the land, and half of them belong to the heirs of my father-in-law's estate. There were six brothers and sisters. So our share is one-half of the one-eighth royalty. My wife also has a share of the heirs' part, which is one-sixth of one-sixteenth of the royalty interest.

My first check after the windfall profit tax started showed $441.56 owners' gross, with $150.83 taken out for the tax. That left me with $290.83. Over one-third went for windfall tax, and that is the way it went for 1980 and 1981, because we have tier 1 oil that is taxed at the highest rate.

One problem with oil royalties is that sometimes we get no check at all. Our wells were shut in for 8 months in 1982 and the first part of 1983 for a workover because they have problems with salt water down there. Also, we never know how much oil they are going to take. Most months, the gross runs about $400, but it has jumped a few times as high as $800. It does not always make sense, the way they pay you.

We have also had some damage to our land because of the wells. They pushed down 22 trees when they did the clearing for the wells, and put in three-eighths of a mile of roads that took land out of production. Then they started putting salt water down an old dry well on the place, and we had to hire a lawyer to get that taken care of, and get the oil company to pay for using that old well for salt water.

Our owners' share of the well is about one-half barrel a day, so I was covered by the two-barrel exemption, and I don't have to file for a refund at the end of the year. They don't take the windfall tax out of my checks any more.

But I do pay Federal and State income tax on my royalties. I also pay an oil lease tax and a real estate tax on the land. The oil made the real estate tax higher, and I just got a notice that the real estate tax is due to go up again.

Our royalty income is important to us. If we did not have it, we would have to cutback. My wife gives her share of the heirs part of the royalty to our two children. Things are hard right now in Chicago, and a lot of companies have cutback on the hours people can work, so the children and grandchildren need the help we give them now. I would help them more if I could get a better check from the oil wells.

We had always planned to move to the farm when we retired—my neighbors call me the farmer because I have a big garden right in the middle of southeast Chicago. But the economy is so bad, and interest rates are so high, that we have not been able to sell our house and move out of the city.

I just feel that we don't get much from our wells at all. With all these taxes we pay to the State and the Federal Government, they don't leave us with much. If they put more taxes on the oil, or put the windfall tax back on small royalty owners like me, they will just about take it all.

Mr. Chairman, I want to thank you and the other members of the committee for hearing what I have to say, and I hope that you will help me keep my exemption and not put any more taxes on my royalty income.

Thank you.

Mr. PICKLE. We thank you.

Mrs. Dunn, do you have a statement?

Mrs. DUNN. Yes.

## STATEMENT OF MARIE DUNN, CERTIFIED TAX PRACTITIONER, FOX, OKLA., ON BEHALF OF THE NATIONAL ASSOCIATION OF ROYALTY OWNERS

Mrs. DUNN. Mr. Chairman and members of the committee, my name is Marie Dunn, and I live in Fox, Okla., a small farming community in Carter County, located in the foothills of the Arbuckle Mountains. I am a certified tax practitioner, and have been in the accounting business for 34 years. My clientele is made up of farmers and ranchers, small royalty owners and small business people.

Oil has been produced in Carter County since 1915. Some of the land which is farmed by my clients has been owned by the same families for three generations. Other has been bought over a period of time by farm families who took jobs in town to get income so they could go from tenant to owner.

I have seen the rural economy of my part of the world change from good to bad and from bad to good many times. In good times, the small communities and farms have prospered because of the income from oilfield activities. But when farmers and ranchers cannot make a living from their land, and drilling slows down, times get hard.

For 2 years, we have seen a boom turn to a bust in drilling and leasing activities, and we have seen inflation and weak prices for farm goods cause severe problems to our farm people. In many cases, the land and the minerals they own were paid for acre-by-acre, at a great sacrifice and with great effort. Many times a part of their mineral interests had to be sold in order to pay taxes or make mortgage payments to hold on to the land.

Many of my clients are elderly, and would not even have to file a return if it were not for the windfall tax. But they had to pay for professional help to claim the $1,000 and $2,500 tax credit or refund, and even though they were exempted with the 2-barrel exemption, they were confused about how and where to file the exemption certificate. I have been told that a lot of folks in Carter County did not file the certificate because they did not understand what it meant, and could not figure out the forms. A lot of elderly people are afraid to file for the exemption or take credits because they are afraid the Government might take away their social security.

Most of the production in my area is from before 1978, and is taxed at the highest rate like the major oil companies. But the major oil companies can pass along the cost of the tax to the consumer. The royalty owner has no place to pass on the tax. For most royalty owners, they will only have one chance in their lifetime to get a producing well on their land. And when that oil is gone, there won't be any more. When a well is depleted for an independent producer, he can get another lease, and drill another well—he has a lot of chances for production.

Many farmers and ranchers have gone bankrupt, and many are just holding their own, with only their oil royalties standing between them and disaster. It is rural America that is furnishing food and fabric materials for 265 million American people and much of the rest of the world, but they are having a hard time. I believe that freezing the barrel exemption at 2 barrels could further bankrupt many of our farmers and ranchers, who are having to sell parcels of land in some places to survive.

I have brought along some examples of how royalty income has helped people get through the past year. See exhibit A.

Rancher A had farm losses of $51,257.65 for 1982. He is single, and over 65 years of age. His royalty income of $30,058.79—more than two barrels a day, but a little less than three—helped offset this loss, and keep him in the ranching business.

Farmer "B" and his wife, ages 63 and 65, managed to make it through another year, even though they had $35,668.25 in farm losses, because of $41,816.47 in royalty income. This let them show a "real" profit of only $6,811.04—not much for a hard year's work. Their well produced a little more than three barrels a day, but they were only exempted from the tax on two barrels. That extra $3,000 in windfall tax they paid would have just about brought their yearly income up to poverty level.

Farmers and ranchers live from year to year on farm loans, which are many times secured by royalty income. That farm loan money is now getting scarce, and more and more of them will have to depend on just their royalty income to get by.

And what, Mr. Chairman, happens to the small business when times are hard in a farm community? In our little towns, the grocer, the general store and the service stations depend on those local dollars. Every windfall profit tax dollar that leaves our county is equal to $3 that would be recycled from one business to another. You should drive through these towns and see the empty buildings on Main Street that once held feed stores, car dealerships, bakeries and clothing stores. We are hurting, and we cannot afford the kind of burden that the windfall profit tax places on all of us.

Our people cannot understand why they were taxed; they don't know how to figure out the complicated requirements for compliance with the tax, and they don't have access to, and cannot afford, the big city specialists they need to cope. And they are growing afraid that their Government will continue to tax away until everything they own is gone.

When it comes to compliance, it appears that many of the personnel from the Internal Revenue Service and the oil companies working in the windfall profit tax area are poorly trained or completely uninformed.

Last September, an IRS field collection agent drove over 150 miles from Tulsa to a farm at Maud, Okla., without advance notice, to demand immediate payment of $1,912.84 in underpaid windfall profits tax. Otherwise, he threatened to place a lien on the farmer's property. The farmer's wife, who was at home alone at the time, had no idea that they owed money to the IRS. In a panic, she called her tax accountant, and learned that the oil company had made a computer error on her 6248, and they owed nothing at all.

The IRS keeps revising requirements, the oil companies cannot keep up with the changes and are still making adjustments on 1980 withholding statements, and the royalty owner—who has absolutely no control over the amount of windfall profit tax withheld from his run-check—is an innocent victim when mistakes occur.

Did you know that there is still no line on the 1040 tax form for overpaid windfall profit tax? And that the royalty owner taxpayer does not receive his tax information from the oil companies until March 31, or later, with an April 15 deadline staring him in the face?

I have to make dozens of calls each week to oil companies and the Internal Revenue Service to get information I need for my clients, and most of the people I talk to have a hard time coming up with the answers. Either the IRS needs to provide better training for their people, or a tax which cannot be interpreted or administered needs to be repealed. Internal Revenue Service and oil company employees have told me that they have hair-pulling nightmares over the windfall profit tax.

Mr. Chairman, a small royalty owner has no way of recovering his tax. He cannot understand this complicated tax. He only wants to be able to hope for a dignified retirement, live without fear of his Government, and pay his just share of taxes without being a target simply because he has oil royalty income.

I am so thankful that I live in America and have a chance to appear before you today to tell my story. I ask for your careful consideration of the problems of the royalty owner, and I appreciate your courtesy in hearing me out.

[Exhibit A follows:]

## EXHIBIT A

Your social security no.
: :

…se, please print or type.

City, town or post office, State and ZIP code

Your occupation ▶ Royalty -rancher

Spouse's occupation ▶

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Presidential Election Campaign** | ▶ Do you want $1 to go to this fund? | x | Yes | ▨ | — | No | Note: Checking "Yes" will not increase your tax or reduce your refund. |
| | If joint return, does your spouse want $1 to go to this fund? | | Yes | ▨ | | No | |

For Privacy Act and Paperwork Reduction Act Notice, see Instructions.

**Filing Status**

Check only one box.

| | | |
|---|---|---|
| 1 | ☒ | Single |
| 2 | ☐ | Married filing joint return (even if only one had income) |
| 3 | ☐ | Married filing separate return. Enter spouse's social security no. above and full name here ▶ |
| 4 | ☐ | Head of household (with qualifying person). (See page 6 of Instructions.) If the qualifying person is your unmarried child but not your dependent, enter child's name ▶ |
| 5 | ☐ | Qualifying widow(er) with dependent child (Year spouse died ▶ 19 ). (See page 6 of Instructions.) |

**Exemptions**

Always check the box labeled Yourself. Check other boxes if they apply.

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 6a | ☒ Yourself | ☒ | 65 or over | ☐ | Blind | Enter number of boxes checked on 6a and b ▶ | 2 |
| b | ☐ Spouse | ☐ | 65 or over | ☐ | Blind | | |
| c | First names of your dependent children who lived with you ▶ | | | | | Enter number of children listed on 6c ▶ | - |

| d Other dependents: (1) Name | (2) Relationship | (3) Number of months lived in your home | (4) Did dependent have income of $1,000 or more? | (5) Did you provide more than one-half of dependent's support? |
|---|---|---|---|---|
| | | | | |
| | | | | |

Enter number of other dependents ▶

e Total number of exemptions claimed

Add numbers entered in boxes above ▶ 2

**Income**

…ease attach …py B of your …rms W-2 here.

…f you do not have … W-2, see …age 5 of …structions.

…ase …ach check …money …der here.

| | | | | |
|---|---|---|---|---|
| 7 | Wages, salaries, tips, etc. | 7 | | |
| 8 | Interest income (attach Schedule B if over $400 or you have any All-Savers interest) | 8 | 23,791. | 31 |
| 9a | Dividends (attach Schedule B if over $400) ______, 9b Exclusion ______ | ▨ | | |
| c | Subtract line 9b from line 9a | 9c | | |
| 10 | Refunds of State and local income taxes (do not enter an amount unless you deducted those taxes in an earlier year—see page 9 of Instructions) | 10 | | |
| 11 | Alimony received | 11 | | |
| 12 | Business income or (loss) (attach Schedule C) ▶ | 12 | | |
| 13 | Capital gain or (loss) (attach Schedule D) | 13 | 1,329. | 63 |
| 14 | 40% capital gain distributions not reported on line 13 (See page 9 of Instructions) | 14 | | |
| 15 | Supplemental gains or (losses) (attach Form 4797) | 15 | | |
| 16 | Fully taxable pensions, IRA distributions, and annuities not reported on line 17 | 16 | | |
| 17a | Other pensions and annuities. Total received 17a | ▨ | | |
| b | Taxable amount, if any, from worksheet on page 10 of Instructions | 17b | | |
| 18 | Rents, royalties, partnerships, estates, trusts, etc. (attach Schedule E) | 18 | 30,058. | 79 |
| 19 | Farm income or (loss) (attach Schedule F) ▶ | 19 | (51,257. | 65) |
| 20a | Unemployment compensation (insurance). Total received 20a | ▨ | | |
| b | Taxable amount, if any, from worksheet on page 10 of Instructions | 20b | | |
| 21 | Other income (state nature and source—see page 10 of Instructions) ▶ | 21 | | |
| 22 | Total income. Add amounts in column for lines 7 through 21 ▶ | 22 | 3,922. | 08 |

**…djustments …o Income**

(…e …struc…ons on …ge 11)

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 23 | Moving expense (attach Form 3903 or 3903F) | 23 | | | ▨ | | |
| 24 | Employee business expenses (attach Form 2106) | 24 | | | ▨ | | |
| 25 | Payments to an IRA. You must enter code from page 11 (........) | 25 | | | ▨ | | |
| 26 | Payments to a Keogh (H.R. 10) retirement plan | 26 | | | ▨ | | |
| 27 | Penalty on early withdrawal of savings | 27 | | | ▨ | | |
| 28 | Alimony paid | 28 | | | ▨ | | |
| 29 | Deduction for a married couple when both work (attach Schedule W) | 29 | | | ▨ | | |
| 30 | Disability income exclusion (attach Form 2440) | 30 | | | ▨ | | |
| 31 | Total adjustments. Add lines 23 through 30. ▶ | | | | 31 | -0- | |

**…djusted …ross Income**

| | | | | |
|---|---|---|---|---|
| 32 | Adjusted gross income. Subtract line 31 from line 22. If this line is less than $10,000, see "Earned Income Credit" (line 62) on page 15 of Instructions. If you want IRS to figure your tax, see page 3 of Instructions ▶ | 32 | 3,922. | 08 |

EXHIBIT A

**Filing Status**

Check only one box.

1 ☐ Single

2 ☑ Married filing joint return (even if only one had income)

3 ☐ Married filing separate return. Enter spouse's social security no. above and full name here ▶ ____________

4 ☐ Head of household (with qualifying person). (See page 6 of Instructions.) If the qualifying person is your unmarried child but not your dependent, enter child's name ▶ ____________

5 ☐ Qualifying widow(er) with dependent child (Year spouse died ▶ 19 ____ ). (See page 6 of Instructions.)

**Exemptions**

Always check the box labeled Yourself. Check other boxes if they apply.

6a ☑ Yourself ☐ 65 or over ☐ Blind

b ☑ Spouse ☑ 65 or over ☐ Blind

Enter number of boxes checked on 6a and b ▶ 3

c First names of your dependent children who lived with you ▶ ____________

Enter number of children listed on 6c ▶ ☐

| d Other dependents: (1) Name | (2) Relationship | (3) Number of months lived in your home | (4) Did dependent have income of $1,000 or more? | (5) Did you provide more than one-half of dependent's support? |
|---|---|---|---|---|
| | | | | |
| | | | | |

Enter number of other dependents ▶ ☐

e Total number of exemptions claimed 12

Add numbers entered in boxes above ▶ 3

**Income**

Please attach Copy B of your Forms W-2 here.

If you do not have a W-2, see page 5 of Instructions.

Please attach check or money order here.

| | | | | | |
|---|---|---|---|---|---|
| 7 | Wages, salaries, tips, etc. | | 7 | | |
| 8 | Interest income (attach Schedule B if over $400 or you have any All-Savers interest) | | 8 | 208 | 12 |
| 9a | Dividends (attach Schedule B if over $400) ______, 9b Exclusion ______ | | | | |
| c | Subtract line 9b from line 9a | | 9c | | |
| 10 | Refunds of State and local income taxes (do not enter an amount unless you deducted those taxes in an earlier year—see page 9 of Instructions) | | 10 | | |
| 11 | Alimony received | | 11 | | |
| 12 | Business income or (loss) (attach Schedule C) ▶ | | 12 | | |
| 13 | Capital gain or (loss) (attach Schedule D) | | 13 | | |
| 14 | 40% capital gain distributions not reported on line 13 (See page 9 of Instructions) | | 14 | | |
| 15 | Supplemental gains or (losses) (attach Form 4797) | | 15 | | |
| 16 | Fully taxable pensions, IRA distributions, and annuities not reported on line 17 | | 16 | | |
| 17a | Other pensions and annuities. Total received | 17a | | | |
| b | Taxable amount, if any, from worksheet on page 10 of Instructions | | 17b | | |
| 18 | Rents, royalties, partnerships, estates, trusts, etc. (attach Schedule E) | | 18 | 41816 | 47 |
| 19 | Farm income or (loss) (attach Schedule F) ▶ | | 19 | (35668 | 25) |
| 20a | Unemployment compensation (insurance). Total received | 20a | | | |
| b | Taxable amount, if any, from worksheet on page 10 of Instructions | | 20b | | |
| 21 | Other income (state nature and source—see page 10 of Instructions) ▶ 1099 NEC Universal Fidelity Life | | 21 | 454 | 70 |
| 22 | Total income. Add amounts in column for lines 7 through 21 ▶ | | 22 | 6811 | 04 |

**Adjustments to Income**

(See Instructions on page 11)

| | | | | | |
|---|---|---|---|---|---|
| 23 | Moving expense (attach Form 3903 or 3903F) | 23 | | | |
| 24 | Employee business expenses (attach Form 2106) | 24 | | | |
| 25 | Payments to an IRA. You must enter code from page 11 (____) | 25 | | | |
| 26 | Payments to a Keogh (H.R. 10) retirement plan | 26 | | | |
| 27 | Penalty on early withdrawal of savings | 27 | | | |
| 28 | Alimony paid | 28 | | | |
| 29 | Deduction for a married couple when both work (attach Schedule W) | 29 | | | |
| 30 | Disability income exclusion (attach Form 2440) | 30 | | | |
| 31 | Total adjustments. Add lines 23 through 30. ▶ | | 31 | | |

**Adjusted Gross Income**

| | | | | |
|---|---|---|---|---|
| 32 | Adjusted gross income. Subtract line 31 from line 22. If this line is less than $10,000, see "Earned Income Credit" (line 62) on page 15 of Instructions. If you want IRS to figure your tax, see page 3 of Instructions ▶ | 32 | 6811 | 04 |

| Employer identification number | Social security number, if any | Employer's [illegible] number |
|---|---|---|
| | | |

If the information on this return is based on a Form 6248 received from another person, check this box (see instructions) and provide the name and employer identification number of the person who furnished you Form 6248. A

| Name | Employer identification number |
|---|---|
| SEE ATTACHMENT | |

## Part I Producer Or Other Recipient

| | | | | | |
|---|---|---|---|---|---|
| Type of Producer | ☐ Individual<br>☐ Resident of U.S. Possessions | ☐ Partnership | ☐ Corporation<br>☐ Foreign entity | ☐ Estate<br>☐ Other ▶ NOT AVAILABLE | ☐ Trust ☐ U.S. citizen or resident |
| Producer Status (check all applicable boxes) | ☐ Independent producer<br>☐ Integrated oil company | | ☐ Member of "related group"<br>☐ Operator | ☐ Producer with no withholding | ☐ Royalty owner<br>☐ Working interest |

## Part II Exempt Oil

| Number of barrels of exempt oil | Tier one (a) | Tier two (b) | Tier three: Newly discovered (c) | Tier three: Incremental tertiary (d) | Tier three: Heavy (e) |
|---|---|---|---|---|---|
| 1 Qualified governmental interests | | | | | |
| 2 Qualified charitable interests | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3 Exempt Indian oil | | | | | |
| 4 Exempt Alaskan oil | | | | | |
| 5 Exempt front-end oil | | | | | |

## Part III Information on Taxable Oil Removed During 1980

| | Number of barrels of oil (a) | Aggregate removal value (b) | Aggregate adjusted base value (c) | Aggregate state severance tax adjustment (d) | Tax liability (e) |
|---|---|---|---|---|---|
| 1 Tier one, other than Sadlerochit oil: | | | | | |
| A Subject to 70% tax rate | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| B Subject to 50% tax rate | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2 Tier one, Sadlerochit oil: | | | | | |
| A Subject to 70% tax rate | | | | | |
| B Subject to 50% tax rate | | | | | |
| 3 Tier two oil taxed at 60% | 449.74 | 17,129.39 | 7,735.96 | 665.51 | 5,236.73 |
| 4 Tier two oil taxed at 30% | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 5 Tier three, newly discovered oil | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 6 Tier three, incremental tertiary oil | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 Tier three, heavy oil | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 8 Total (add lines 1 through 7) | 449.74 | | | | 5,236.73 |

## Part IV Windfall Profit Tax Liability for Oil Removed During 1980

| | |
|---|---|
| 1 Amount of windfall profit tax liability for oil removed during 1980 (from Part III, line 8, column (e)) | 5,236.73 |
| 2 Amount of windfall profit tax withheld with respect to oil removed during 1980 computer error — Line 2 should equal line one | 3,323.89 |
| 3 If line 1 is greater than line 2, subtract line 2 from line 1. This is amount of underwithheld windfall profit tax | 1,912.84 |
| 4 If line 2 is greater than line 1, subtract line 1 from line 2. This is the amount of overwithheld windfall profit tax | |

## Part V Amount of Windfall Profit Tax Withheld from Payments Made in 1980

| | |
|---|---|
| 1 Amount of windfall profit tax withheld from payments made in 1980 (regardless of when liability for windfall profit tax arose) | 2,663.57 |

Mr. PICKLE. We are glad to have your statement.

You have made a very good statement. We appreciate it.

Mr. Stafford, do you want to add anything additional?

Mr. STAFFORD. Several things.

We have received in the last several days letters directed to this committee from all over the United States. I want to submit that respectfully to the chairman.

Mr. PICKLE. We accept that. I don't know whether we will make all that data available. That looks like a double-sized Webster's dictionary. We are glad to have it. We will be certain that the relevant part is made part of the record.

[The letters referred to have been retained in the subcommittee's files.]

Mr. STAFFORD. I can summarize what most of those people say very quickly.

No. 1, people don't believe they should have been taxed under the windfall profits tax in 1980, and it is based on a unique pattern of ownership. They don't consider themselves producers of oil, although by tax law definition they are producers. They consider themselves to be property owners—whether it is in place or when produced, according to which State law.

No. 2, they believe they should be exempt from the tax if not repealed—since, as you heard today, seven layers of taxes can be levied on their income.

In Louisiana, for instance, we have a member who has 87 cents of each dollar taxed away; 7 cents of the remainder goes to lawyers and accountants for compliance with the various State laws.

No. 3, we feel that if repeal is not possible, we should at least have taxes that are equal to an independent producer and not the higher rate now.

We now pay equal to that of major oil companies. Unlike both producer groups, we have no place to make up our loss. We believe if the repeal is not forthcoming, the proposed 3-barrel-a-day exemption should be allowed for 1985.

We believe that the depletion allowance, which is allowed on the sale of an irreplaceable asset should be continued. And that would—loss of depletion allowance for royalty owner would remove another 18 cents from income already overburdened by local State and Federal taxes.

We read this into the record. I understand the staff has circulated questions on royalty ownership that I would like to address. We have a copy of that document. And the survey material that we have been using since 1980 on demographics of royalty ownership, as you can tell from the people here, based on patterns of the majority of oil fields in the United States and tax laws, the majority of royalty owners are elderly. We substantiate that in two surveys.

The data has been approved or sanitized by Phillips, Sun, Shell, and several other oil companies, plus a survey done by Senator Boren, of Oklahoma. But we do plan to address the questions in that questionnaire that we did get, because we have the answers.

I thank you very much.

[The prepared statement and attachments follow:]

## STATEMENT OF JAMES L. STAFFORD

My name is James L. Stafford and I live in Ada, Oklahoma, a town of about 15,000 people in the Southeastern part of the state. I was a founder, back in 1980, of the National Association of Royalty Owners. I served for two years as its chairman, and am currently serving as its executive director. We have 4,000 members in 50 states and also represent the interests of about 38,500 members of regional, county and state mineral owner groups in the nation.

I will begin today by observing that so-called Windfall Profits Tax is still being levied at a time of the most severe shake-out in oil industry history. Some members of Congress and several of the nation's leading newspapers have failed to note this disaster. Several still remain convinced that the industry should bear more tax burdens. Hundreds of oil-related companies are going into bankruptcy each month -- many as a result of unwise and hurried tax and regulatory legislation. And many oil and gas properties are being shut in across the nation pending court action.

Further, tax compliance is proving an enormous burden and financial expense for victimized royalty owners, who on the whole represent an older and poorer group of American citizens. Because of threats of repeal of their small exemptions during every session of Congress, many are afraid to make needed financial commitments, some vital to health care decisions. And the tax is further putting a drain of untold consequence on the rural and farm economies which suffer from its impact. These areas are already severely depressed based on external market factors and financial problems out of their hands and currently out of control.

Royalty owners have long been considered the poor relations of the oil industry. Although technically we are the landlords, in most cases, we have had little if nothing to say over our destiny. Laws were written in most producing states over the years without our knowledge or our say that stripped away many of our rights. And oil company pricing and production practices largely go on totally uncontested and unknown to the royalty owner. In the past three years, this imbalance has been changing rapidly, through our efforts and the creation of small regional organizations. Yet historically, we have more often than not been the victims rather than the victors in our dealings!

My appearance here today is to support the following points based on three years of insight and experience with royalty owner problems. Number One, we believe that the royalty owner should not have been taxed under the 1980 windfall profits tax and that consideration should be given to total repeal as it applies to these tax victims. This is based on the unique nature of ownership. We further hold that this group of 2.5 million citizens was victimized by a whiplash from decades of untrue stereotyping and a punitive tax action over which they had absolutely no control, and no warning. Number Two, we believe the nation's royalty owners should be exempt from the tax if it is not repealed, since we pay up to seven layers of taxes already on our income in many states, including federal income taxes and the burden of compliance is beyond the scope of the elderly, rural, and largely unsophisticated royalty owner taxpayer. Number Three, we feel that if repeal is not possible, we should bear taxes that are at least equal to those of independent producers and not the higher rate we now pay equal to that of major oil companies. The majors can offset domestic taxes with overseas profits and increased prices to consumers while we, unlike both producer groups, have no place to make up our loss. Further, if repeal is not forthcoming, we believe the proposed 3 bbl. a day exemption should be allowed for 1985, as enacted by Congress in the ERTA of 1981.

And Number Four, we believe that the depletion allowance, which is allowed on the sale of an irreplaceable asset, should be continued. Contrary to some Congressional comment and some misguided public discussion, percentage depletion is allowed to over 200 minerals from our earth and should continue, since unlike the trees of our forests (also classed as depletable by the tax code), petroleum is a non-renewable substance and once extracted is exhausted for eternity -- often less than seven years following discovery.

Loss of the depletion allowance for the royalty owner would remove another 18% from income already overburdened by local, state and federal taxes that can total as much as 87% of income.

Mineral ownership has a long history. The ability to sever surface ownership and mineral ownership goes back in English law before the Norman Conquest of 1066. In the Bible, the Book of Genesis records a dispute over mineral rights versus surface rights. In the United States this freedom is guaranteed by the Constitution.

But in 1980, when the Windfall Profit Tax Act was passed, Congress had no facts about their intended tax target, except some false stereotypes and a generalized assumption that royalty owners were in large part wealthy. That could have been quickly contested, but wasn't, by those who allegedly were representing our interests. After NARO was organized, we turned to the major schools and universities and to the major oil companies hoping someone (had) compiled some facts, figures and demographics about who we were and where we were located. There was not a single institution with substantial data about royalty owner demographics except a generalization that "there are a bunch out there. They are mostly elderly. Most have moderate to small monthly mineral checks."

NARO started digging up the facts. The first thing we did was to work with the office of Senator David Boren and Eason Oil Company, who agreed to survey their royalty owners in seven states. (Exhibit B) Later Senator Boren received data from a Denver-based firm. The data we compiled was later verified, as on track, by division order departments of Sun Oil, Phillips, and Getty. Additional proof of our assumptions was given by a survey taken among a West Texas mineral owner association. We learned that 73 percent of royalty owners are over 61; 45 percent are on Social Security; 27 percent are widows; (the majority of royalty owners are women), 12 percent are disabled and five percent are in health care facilities.

Because of the nature of ownership and the age of most of the oil fields of the nation, mineral ownership is largely the domain of people past retirement age.

The average age of a NARO member, it should be noted, is over 70 -- the age and income level hit hardest by the tax.

The average run check, we learned from an Oklahoma banking association, per production unit, is about \$250, with only about 1 percent of mineral owners receiving oil income exceeding the salary of a U.S. Senator. Only 8 percent of respondents to the West Texas survey had incomes from single unit production in excess of \$500.

There are very, very few large tracts under one mineral owner's name in any of the older producing states. I have attached a map from Oklahoma showing a typical older producing field, with the hundreds of fractional owners listed. (Exhibit A) The property, usually signified by a dot, will have the surface owner's name written at the top of the tract and below it the mineral ownership.

We looked at hundreds of such maps and division orders (Exhibit C). A document issued in Louisiana by a purchasing company we have attached shows 109 mineral interests in a 160 acre property. It is an absolute rarity that you find one person owning large blocks of land, except as a company or individual devoted totally to that business. The major holders of large farms and major mineral interests today are corporations and the little interests continue to get smaller.

John Wayne is dead and so are the days of the big spreads, except for those owned by agri-corporations. You can't farm a small piece of land and profit anymore. It is big business, and it is driving the small operator from the land, except when they are propped by outside cash flow, such as outside jobs or royalties. The current trend, based on the tax policy toward independent producers, is quickening this trend as the major oil companies are acquiring more and more acreage as the short lived boom of the 70's quickly turns to a bust, with hundreds upon hundreds of bankruptcies among oil related businesses.

A neighboring rancher, a royalty owner, told me that he had to pledge royalty income to borrow $200,000 to help set up his son in farming. He leases all the land he now farms. So this outlay was totally for equipment. The debt service alone means the son must face ten years of borderline poverty before turning a living wage from his investment. This case is often repeated and it is healthy for our nation's survival.

In the oil states of the nation, the purchase of mineral rights along with the surface rights of the land has most usually exacted a premium. Since the 1920's, a person buying land remotely near production has had to pay handsomely to acquire the mineral rights. In hard times, these rights have been divided, bartered, traded and sold to acquire needed farm equipment or to pay taxes to hold on to the land. It is for that reason that a tract of land in a producing state may have one surface owner, but hundreds of mineral owners under the land.. In the Depression years, much mineral acreage was sold off in order to pay taxes to save the surface acreage, or to pay off debts. Deaths and further divisions have created royalty owners in every state of the nation. Geologists tell us that potentially productive areas of the nation, largely in the Northeast quadrant of the Appalachian Overthrust might mean a figure five times the current estimate of 2.5 million royalty owners within the next 100 years.

In my part of Oklahoma, as in many parts of producing states, we have little or no industry, so thus no pensions. We have no brokerages, and thus no stock retirement plans. Since we mostly are self-employed, we must make our own plans about retirement income, if we can ever afford that luxury. My Congressional District, incidentally, is the 423rd poorest such domestic district, 12th from the bottom, despite our mineral resources. Buying potentially productive mineral interests, usually for a few dollars at a time, has long been a practice in anticipation of retirement. The odds are still much better in Las Vegas than in the oil field, for the low-income investor. It is simply the only thing we can afford, since property is often sold in very affordable small units.

Royalty owners do not look upon the windfall profits tax lightly and President Carter's picture is on few farm-house walls. Folks do not understand why they must suffer for the public relations sins of the major oil companies by being taxed at the same rate as the Exxons and Texacos. Since, as stated, many pay seven layers of taxes, (county, school and road land tax, ad valorem, state wellhead and property, plus county, state and federal income tax) They bitterly resent being singled out for additional tax burdens on their oil royalty income. We want to simply be taxed like our cousins, who may have invested in real estate in Massachussetts or in a New York mutual fund. Their income is called prudent planning, ours obscene and a windfall.

It is clear that the major victors from the recent oil boom have been the county, state and federal governments. A Shell Oil Company estimate, provided last month in Congressional testimony, was that for every dollar rise in oil prices, the government's share is 80 percent of the revenue. A high bracket royalty owner in Louisiana we know has but 13 cents left from every dollar, after these taxes are taken out. He then has to pay seven cents of the remainder for compliance. It would seem that our sector of the economy could be spared further torment.

Written testimony from some royalty owners around the nation is submitted. It expresses their anger, frustration and confusion far better than cold statistics and generalities in scientific surveys. (See Exhibit D)

Few understand this WPT tax! It seems only a handful of professionals claim they do. Half of them may be lying. The IRS offices cannot interpret or administer it. The average tax accountants and tax lawyers can't stay up with it. The oil purchasers cannot efficiently implement it. The producers can't cope with the paperwork burden it imposes and are handicapped in developing new reserves because of the snarl of conflicting and ever-changing rulings governing a law that was punitive in concept, geographical in its impact and lethal in its devastation.

And yet, caught in the middle, is the single sector of Americans that could not be more vulnerable -- our folks, the royalty owner. They can neither control nor comprehend the situation. Overwhelmingly elderly, largely unsophisticated and rural, he or she is further denied geographically and financially the few urban-located oil and gas specialists with the technical know-how to guide these hapless victims through the bureaucratic holocaust called the windfall profits tax.

Royalty owners, whose advanced age or limited income mean they may not even be required to file federal income tax returns, suddenly have to cope with forms such as 6248, 6249, 1099, 6783 and 843.

The king pin store front tax preparers such as H & R Block won't even touch a royalty owners return.

J. K. Lasser's 500-page income tax guide for 1982 devotes one paragraph to royalty owners by stating "the windfall profits tax is not discussed in this book."

A Getty Oil Company official in Denver, who deals daily with royalty owners, states that his office receives calls from scores of lawyers and accountants seeking advice on filling out their clients returns. He says he's had calls from royalty owners saying "please buy my interests, I can't handle the paperwork anymore."

The NARO office is beseiged at tax time, not only from our members, but from specialists, thinking we may have some inside information that may help them cope correctly with the layers of forms.

Several sources, and we would back them up based on our experience, state that over half of the nation's royalty owners granted a $1,000 tax credit for 1980 didn't claim the benefit. It was too complicated is the general assumption. It is my own observation, in talking with hundreds of elderly about the matter, that this was, and is, based on fear. Rural people are distrustful of anything that might evoke an audit and they feel, to a large degree, that any question the government might have would result in a punitive loss of social security. They would rather not attempt the forms than risk making a mistake.

This curtain of fear is not entirely confined to rural areas. I have noted it among city dwellers as well. I find it a sad commentary, Mr. Chairman, that such a fear exists and forces many of our 65 million elderly people to live in dread of our government.

But there's no doubt about it. The tax process is complicated. Our office attempted, with the help of some very good professionals, to put together a four-page guide to royalty owner exemptions. It was rewritten, concised, tested and rewritten again to be simple and as easy to understand as possible.

The second comment we heard after it was mailed to our members came from an elderly Pontotoc County Oklahoma widow, who said, "I liked it because it was only four pages. But those four pages would take me four years of college to understand, and I'm only expected to live two more." And this was our finest attempt to make common sense from the IRS material, which in recent years has gotten too complicated for many of our nation's best CPA's -- judging from the calls to our office.

Our office, from calls received from tearful members believes that, again this year, as many as half will not claim their exemptions. The reasons will be 1) they don't understand the computerese forms sent them by the purchasing companies, 2) many won't receive their forms until well after the filing date and won't know how to file an amended return, 3) their accountants won't understand how to file for the exemptions or are afraid to make a mistake and be called before the government to explain an error which would cost them a half year's income in legal and accounting fees to clear up.

One thing else must be emphasized, Mr. Chairman. Royalty owners are classified as "producers" for tax purposes and under the provisions of the windfall profits tax. They are not, repeat, are not, producers! They are property owners. Just as surely as they own their tractors, a house or a farm, they own the minerals beneath the land, "whether in place or when produced." If they have a good crop, they are not punished, if they sell off part of their land to pay taxes, they are not punished. Yet they don't have many options with mineral ownership. If the well drilled is dry, they can't move a couple of sections south and hope for a producer. And a dry hole means hopes are usually gone forever, and their land is immediately devalued because of the effort.

The question has been raised -- how do we justify a 3-bbl., as opposed to a 2-bbl. exemption? Why shouldn't Congress freeze the royalty owner at two barrels? Doesn't a 3 bbl. exemption let a lot of fat cats, who can afford to pay, get off the hook? It all depends on how you define "Fat Cat." A royalty owner who received income on three bbls. or oil per day makes, at today's prices about $31,755 per year -- the salary of a Step One GS 12 in the federal government. He pays severance and gross production taxes at a very minimum of from 5 to 12%. A single taxpayer would also pay $7,882 in federal income taxes, leaving him or her approximately $21,650 to whoop off. This doesn't include the layers of other assessments levied in most counties.

The WPT savings difference between the two barrel and the three barrel exemption is approximately $3,000. Not a princely sum by fat cat standards. But it would pay for one semester at a state university, five days of non-surgical hospital care, fertilizer for 200 acres of alfalfa, three months in a nursing home, and earn interest of approximately $164.88 in a passbook savings account, or pay for 30 hours of legal aide in case the IRS decided to audit his return.

The argument has been made that exempting the royalty owner from the windfall profit tax will not produce one additional barrel of crude oil. In tax debate, some independent producers charged that the royalty owner was not a "productive" element of the industry. This was calculated so our taxes would lower theirs, which did occur. But some royalty owners across the nation are refusing to sign leases allowing exploration and development of the mineral properties which they own, rather than cope with taxes. This can, if accelerated, create havoc with a producer's ability to drill. And our folks are all productive members of the American society. They buy homes, pay their doctor bills, raise crops and livestock, pay income taxes, put money in savings accounts and are the lifeblood of small rural communities all across the country.

As a person who worked for a decade in this city and in New York, I can understand why we were singled out for the tax, all political considerations aside. For 50 years a sure fire East Coast newspaper circulation builder has been a rags to riches story about a poor farmer striking oil and moving to Beverly Hills. Before that, the journalistic cliche was an Oklahoma indian sitting in front of a car hitched to mules while a gusher boomed in the background. (One Oklahoma City photographer has a stock file of 200 such shots that his father took, using a prop background and a borrowed Indian who lived 100 miles West of the nearest reservation). A newspaper sale a month kept them in business for several years, he says, in the 1920's.

There are far more riches to rags stories today than vice versa.

First, there are only two isolated areas where the nature of broad ownership and production levels allows overnight wealth to happen -- one is in Louisiana's Tuscaloosa Trend and the other is in two counties of Oklahoma's Deep Anadarko Basin. Neither, it should be pointed out, are oil plays. Both are natural gas areas, and both are suffering today economic devastation beyond belief because of the Natural Gas Policy Act which has created market chaos. Most of the millionaires from 1980 are today scrambling to pay taxes and debt service fees since production levels are almost at a standstill. The Basin, incidentally, has bankrupted far more people than it has made millionaires, and only about 300 royalty owning farm families, according to one estimate, have become wealthy in this, the most dramatic wildcat play of the last 50 years.

But this stereotype is still the journalists' stock in trade for a trip to the oil states. They ignore completely the real facts while searching for a J. R. Ewing, or a Jed Clampitt, when the reality is, the divisions of interest are usually so small, the costs so high, that a trip to Las Vegas would uncover more instant success stories.

There is no doubt that royalty income made many fortunes in the early days of the industry. This is the basis for many corporations, institutions and philanthropies both in the Southwest and on the West and East Coasts. But these fortunes were made when there were no spacing limitations, and wells were produced full bore. Then, vast spreads were owned by single individuals, and the laws allowed enough chicanery to exist so a smart wheeler dealer could pillage enough farmers to acquire an overnight fortune.

Today's royalty owner is often pictured as receiving thousands of dollars per acre in bonus, with royalties running up to 50% of production, which was once the standard royalty before the 1900's.

With the exception of certain very small parts of Texas, Oklahoma and Louisiana, the nation's extremely hot spots, most of the nation's royalty owners are locked into 1/8th royalty on production. Today's royalty fortunes, are in the hands of a few who are in the business full-scale with accountants, lawyers and the machines needed to cope with this business in today's sophisticated environment.

In closing, it must be stressed once again that the boom is over and the golden goose is dying if not dead. In my part of the world, 24,000 oilfield workers are without a job, while 600 high cost rigs are idled. Further taxation would lead to eventual nationalization, which would lead to $200 a barrel oil if the bureacracy applied the same brand of zeal to oil production it has applied to Amtrack.

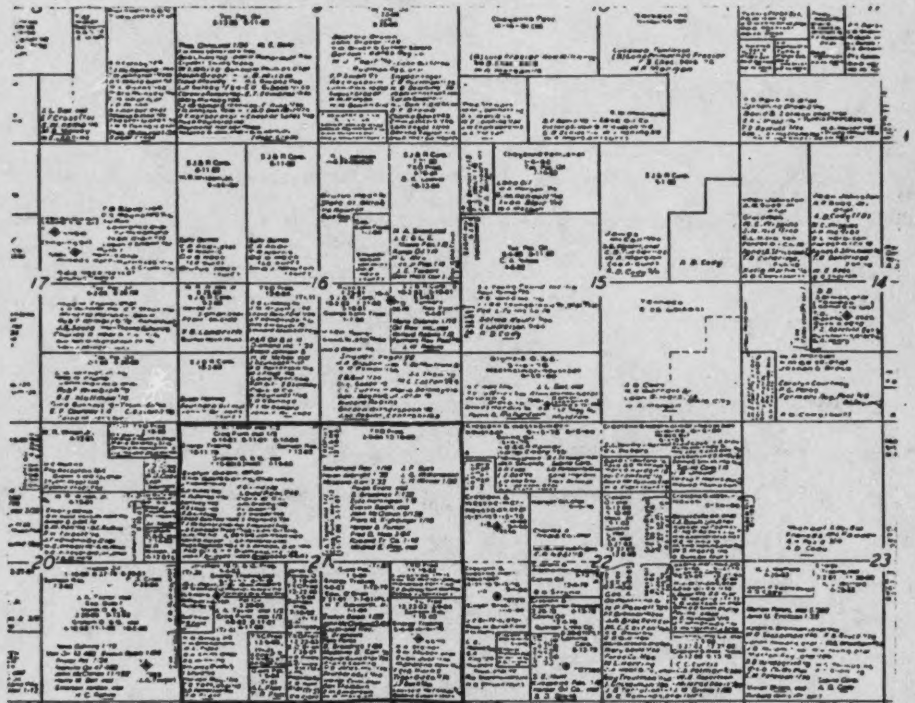
Regardless of national policy trends, we believe royalty owners did not deserve severe taxation nor can they afford any cuts in exemptions won by ERTA. Taxation of the innocent to punish the guilty is what we received in 1980, if earning a profit can be considered a criminal act by the oil producers.

Finding oil, regardless of the boasts of promoters, is still a high risk gamble. John Beard of Oklahoma City disclosed last week that he had drilled 75 dry holes in a row before getting a marginal producer. He says there are no more 100 million barrel fields left in the nation, yet tax policy seems to suppose no end in sight of domestic production.

It is our contention that compliance with the tax, and the cost of collection by the government in light of dropping prices for crude, should make the windfall profits tax, as applied to royalty owners, a candidate for total repeal.

OWNERSHIP MAP OF COAL COUNTY, OKLAHOMA **EXHIBIT A**

Surface owner name and operator name noted in block letters at the top of each tract. Mineral (royalty) interests owners listed in italic below. This map shows all or part of 20 sections of 640 acres each. Section 21 shows approximately 109 royalty interests, not including et als.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CENTRAHOMA
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EXHIBIT B

## EASON OIL SURVEY

### Results of Eason Survey

| | | | |
|---|---|---|---|
| 1. | Royalty Owner | 83% | (.833) |
| | Override | 8½ % | (.085) |
| | Working Interest | 8 % | (.081) |
| 2. | Ages | | |
| | 20-35 | 1½ % | (.0158) |
| | 36-47 | 6 % | (.059) |
| | 48-60 | 19 % | (.0189) |
| | 61-75 | 52 % | (.521) |
| | Older | 21 % | (.213) |
| 3. | Widow | 27 % | (.267) |
| | Divorced | 3 % | (.03) |
| | Disabled | 12 % | (.120) |
| | Welfare | .4 % | (.004) |
| | Unemployed | 11 % | (.112) |
| | Soc. Sec. | 45 % | (.449) |
| | Nurs. Home | 2 % | (.020) |
| 4. | Check Decreased By: | | |
| | 25% | 54 % | (.543) |
| | 50% | 32 % | (.324) |
| | 75% | 8 % | (.078) |
| | More | 5 % | (.053) |
| 5. | Tiers | | |
| | Tier I | 54 % | (.541) |
| | Tier II | 25 % | (.25) |
| | Tier III | 21 % | (.204) |
| 6. | Did you realize the WPT would affect your interest? | | |
| | Yes | 54 % | (.539) |
| | No | 46 % | (.46) |

①

**EXHIBIT D**

May 1-1983.

MR L F SCHILT
1628 KEARNEY
LARAMIE WY 82070

Written Testimony on over sight Comm. on Ways & Means (Born Sept-26-1903. Will be 80 in 5 months -)

For your information

① I use the Royalty income (whats left.) to pay for servies that I can not do for myself -, House Care, yard work, painting - new roof - major House repairs to keep House in safe condition., also medical expense - eye glasses - and drugs are taking more of my fixed income each year.

② Mineral rights were enherited from my wife, deceased in 1978. She enherited from her parents - divided between three children. my Interest, as was hers are as follows

Husky oil Co - % of interest .00049020.
Amoco " " " " .0001226.
Marathon oil Co % of Interest .0095800.

These Interest do not make me a Oil Baron. Production For 1982 from the above Company was 2.1 Bls per day = so the repeal of the 2 & 3 Bls per day would cut my Income - by 50% -, then when you take out Wyo severance tax and Production tax it would leave very little income to supplement my fixed retirement Income.

(2)

The Royalty owner pays Income on the gross, less state severance tax and production tax

3) I have a good C.P.A. He understands the W.P.T. but it is costing me at least $300 per year for this service, but one has to have expert Help and advice.

For Example on 1981 production I paid an additional $412.00 over and above what Amco with Held - which they finaly adjusted -, But on there 1982 records - they made a correction - as I had over paid 412.00 C.P.A is now filling for a refund = but these errors - cost me money - and additional expense to me for the C.P.A's work =

(4) As the price of oil goes down = so do the monthly checks; and a repeal of the 2-3 Bbl - would reduce my Income - to the point where fixed retirement Income. would force many changes.

I have no money to waste, but would like to live out my life with out a Burden to my family - or to County - State or Federal Goverment, and at my age due to health - can not rejoin the labor Force. Our tax systems becomes more unfair each year - taking from those who have tried to take care of there selves -

Louis F Schuld

Mr. Pickle. Thank you, Mr. Stafford.

You have certainly made a very graphic presentation of your situation and your problems.

A lot of people think that royalty owners are the rich and opulent, who just clip coupons in the back room and do nothing to earn it. You don't look like a bunch of rich, opulent coupon-clippers to me—certainly not if you run a garden, and make out tax forms, and deal mostly with elderly people.

But let me ask you a question that we constantly hear here in the Congress.

When we passed this windfall profit tax in 1979–80, I thought we should not tax royalty owners, but we did. We had to wage a war to preserve our oil and gas industry. It was a good campaign but Congress did declare war on royalty owners. They were taxed at the highest rate. Subsequently, though, we were able to give a credit for 1980 and 1981; and a 2-barrel exemption for 1982, 1983, 1984, after which we upped it to 3 barrels.

So, you do get some relief.

In spite of that, though, there are many in the Congress that say this is unearned; that you have no right to it; you should get no incentive; that you are not a producer.

You are really not involved in the actual production and this is a source of resentment by a lot of people who are not familiar with the royality owner issue.

So, my question to all of you is, do the decisions of royalty owners impact on the economics of exploration, development, production of the oil and gas industry? Do you impact on the economics of this industry?

Mr. Stafford. I think after the tax was passed, Mr. Chairman, a lot of people in your State refused to lease. There are a great many in Oklahoma still that will refuse to lease until Congress goes one way or the other.

They are just like our people, worried about their exemptions—they are not making decisions they should be making on health care decisions and other things. But you take a look at the economics of the oil business; the royalty owner is pledging his mineral assets, usually which are bought in addition to the surface—I have this place attached here where there are 109 mineral owners under one 160-acre tract in Lousiana. I have them next to my own county—to show how much those are divided.

We are pledging our land, just as other people who pledge dollars and cents toward the expertise of that operator and his geologist in finding oil. And if I have paid, as I have in the past, $5,000, $10,000, for a unit of mineral property, that is my stake in production when and if it occurs.

In terms of the income, any bank in the State, in the smaller towns of Texas, Oklahoma, Louisiana, will be quick to tell you that once that tax hit, decisions started dropping to a standstill for things like washing machines, for things like used cars, pickups, farm equipment. And that is still true—simply because, where you have 45 people working with one oil rig, you take under one well, where you might have 2 dozen royalty owners with families, and that money is going directly out into that economy.

So, I could write a chapter on the economic impact.

Mr. PICKLE. Well, we need to have that story better understood by Members of the Congress, because a lot of people think royalty owners don't have an impact. I guess we should go back to basics. If we don't have the land, you will never have production.

I assume you are saying you are just as much a part of it as the driller.

Any other questions?

Mr. ANTHONY. Thank you, Mr. Chairman.

Mr. Stafford, I just want to welcome you back before the committee again. The last time you appeared, it was a full committee hearing on possible avenues to raise revenues because of the possibility of huge Federal deficits. It may be we will be back at it again before this year is out.

But I would, Mr. Chairman, request that two documents that were prepared for us by the staff for our briefings be submitted for the record. I believe these documents help prove a point that these witnesses have already made. I think it also helps establish the justification for the 2-barrel exemption that we have presently and the 3-barrel exemption which will soon be in effect.

What I am referring to is a study that talks about the distribution of net royalty income for 1981. There is a footnote that indicates royalty income attributable to nonoil and gas interests. But it is our understanding it would be very minor; it would not distort these basic figures to any great degree. Take $50,000 and below, and we all know today $50,000 of a joint income is not very much; anybody making $50,000 today and paying ordinary income tax on it is just not living too high on the hog.

Seventy-nine percent of the cumulative returns would be at that category and below. So, you can see that the 2-barrel exemption is mainly affecting people in the smaller categories. I think this is good tax policy. We should try to help those that are on the lower end of the scale.

But when you look at the revenue number, you see that they only represent 35 percent of the total royalty income, and that $50,000 and above represent 65 percent of the net royalty income.

So, again, I think this still proves a very strong point; that Congress acknowledges they were wrong. In trying to right that wrong, they tried to distribute royalty income according to our progressive income tax policy; that is, if you are above $50,000 and in the high category, you still get the exemption but will be required to pay more taxes. Obviously, those people are in a better category, and are more able to pay that tax than the people down below.

I think that we can use the documentation in your statement to prove not only to this subcommittee, but to the other members of the full committee, that this exemption is justifiable and should not be repealed. And, as far as this one member is concerned, I have fought from the very beginning against any tax on royalty owners. I worked closely with your association. I can tell you we will not give up on those efforts. We will obviously fight any repeal effort. We will fight any freeze effort. We will just continue to try to make a case, as you have today, for the record. And that is that there is really no energy policy reason, and no tax policy reason, why royalty owners should be put in the category they were. Royalty owners are literally the forgotten taxpayer when that first tax bill was put together.

I just want to close with one statement.

Mr. Stafford, in your testimony—and the pages are not numbered, so I cannot tell you where it is.

Mr. **Stafford**. The upper left-hand corner, I think.

Mr. **Anthony**. You will recall this statement. It says: "Royalty owners do not look upon the windfall profit tax lightly and President Carter's picture is on few farmhouse walls." I would like to encourage you not to put up any photographs of President Reagan.

Mr. **Stafford**. They are coming down rapidly.

Mr. **Anthony**. President Reagan campaigned on the promise of repealing the windfall profit tax. His representative testified in behalf of the windfall profit tax, and our chairman questioned him very carefully about the change in policies, and the justifications for that stand. He gave an explanation and I don't know if you heard it or not, but even if you did I don't believe you would go back to Oklahoma and be sold on it. If there are going to be any photographs put up, I will encourage your royalty owners to take one of you and stick it upon the wall.

Mr. **Stafford**. Thank you very much. Can I make one final statement, Mr. Pickle?

Mr. **Anthony**. Mr. Chairman, I did not get a response as to whether or not I would be permitted to insert these two documents into the record.

Mr. **Pickle**. Yes; all of these documents are part of our working papers and these two in particular will be made part of the record at this point.

[The information follows:]

TABLE 7.—ALLOCATION OF ROYALTY INCOME BY INCOME (AGI) CLASS

| Income class (adjusted gross income) | Number of Returns [1] (showing net royalty income) | Percentage of total returns | Cumulative percentage of total returns | Dollar amount on return [2] (in thousands of dollars) | Percentage of total dollar amount on return | Cumulative percentage of total dollar amount on return |
|---|---|---|---|---|---|---|
| Without adjusted gross income | 20,734 | 2.63 | 2.63 | 153,776 | 2.60 | 2.60 |
| | [3] (2,001) | (6.24) | (6.24) | (128,703) | (45.56) | (45.56) |
| $1.00 to $10,000 | 135,507 | 17.19 | 19.82 | 229,006 | 3.48 | 6.88 |
| $10,000 to $20,000 | 153,108 | 19.42 | 39.24 | 461,892 | 7.82 | 14.30 |
| $20,000 to $30,000 | 131,476 | 16.68 | 55.92 | 504,195 | 8.54 | 22.84 |
| $30,000 to $40,000 | 99,183 | 12.58 | 68.50 | 326,651 | 5.53 | 28.37 |
| $40,000 to $50,000 | 80,948 | 10.27 | 78.77 | 396,045 | 6.71 | 35.08 |
| $50,000 to $75,000 | 79,207 | 10.05 | 88.82 | 778,385 | 13.18 | 48.26 |
| $75,000 to under $100,000 | 30,320 | 3.85 | 92.67 | 325,521 | 5.51 | 53.77 |
| $100,000 to under $200,000 | 39,150 | 4.97 | 97.64 | 1,033,531 | 17.50 | 71.27 |
| $200,000 or more | 18,623 | 2.36 | 100.00 | 1,697,711 | 28.73 | 100.00 |
| Total | 788,256 | 100.00 | | 5,905,712 | 100.00 | |
| | (32,058) | | | (288,473) | | |

[1] Table does not reflect royalty income paid to those not required to file.

[2] Includes royalty income attributable to non-oil and gas interests; estimates indicate that such amounts are relatively small and are distributed in the same manner as other types of royalty income.

[3] Numbers in parenthesis reflect returns with net loss royalty income (due primarily to percentage depletion).

Source: Staff Analysis of Preliminary 1981 IRS Data.

## ALLOCATION OF ROYALTY INCOME BY AGED EXEMPTION

[In thousands]

| | Without Aged Exemption | | With Aged Exemption | | Total | |
|---|---|---|---|---|---|---|
| | Returns | Amount in dollars | Returns | Amount in dollars | Returns | Amount in dollars |
| Royalty income total | 434,018 | 2,329,572 | 273,000 | 1,883,537 | 707,018 | 4,213,109 |
| More than $50,000 AGI | 97,542 | 1,418,271 | 41,515 | 986,203 | 139,057 | 2,404,473 |
| Royalty loss total | 27,583 | 256,358 | 9,714 | 51,999 | 37,297 | 308,357 |
| More than $50,000 AGI | 13,870 | 167,834 | 1,906 | 30,311 | 15,776 | 198,145 |
| Net royalty income total | 461,601 | 2,073,214 | 282,714 | 1,831,538 | 744,315 | 3,904,752 |
| Percent | (62.0) | (71.4) | (38.0) | (28.6) | | |
| More than $50,000 AGI | 111,412 | 1,250,437 | 43,421 | 955,892 | 154,833 | 2,206,328 |
| Percent | (72.0) | (56.7) | (28.0) | (43.3) | | |

Source: Statistics of Income, 1980 Individual Income Tax Returns (unpublished tables).

Mr. **Stafford**. Just one further thing, if I can, in one sentence try to summarize. A lot of these figures are very, very distorted. They overlook one situation. We do not believe that 50 percent of the royalty owners of the country even filed for the thousand credit at the end of 1980.

Mr. **Pickle**. Why?

Mr. **Stafford**. They are terrified of getting an audit from the Government, and this year we think we will see the same thing on the 2-barrel exemption.

We have a man here that represents a small farm up in northern Oklahoma, and the people who live up there, there are just no professional tax people, and they get bogged down and say rather than have to face an audit and have to pay a half year's salary to get out of it, hiring CPA's, I will just forget about it.

This has become a pattern and I hope, within the next 3 or 4 months, we can substantiate this, but we have seen enough of it to say that it is a very, very sad commentary.

Mr. **Pickle**. I would hope you would give us some documentation of that statement. If you can give us figures to show that is the case, I think it would have a very definite bearing on the Congress.

I was concerned with the statement that people wouldn't file because they would lose their social security. I can't understand that, but I guess you are fearful of what might happen.

Mr. Stafford, in view of that information, we would like to have that data.

We thank you all for your testimony.

Mr. **Stafford**. Thank you, sir.

Mr. **Pickle**. Our next panel will consist of Mr. Charles Lindy Long, Mr. Larry Tveit, Mr. Ken Luff, and Mr. Hank Hankla.

Let me identify the panelists here. You have Mr. Charles Lindy Long. Which one is Mr. Long? Mr. Long represents the Royalty Owners and Independent Oil and Gas Producers of Arkansas. He is president of the Long Brothers Co.

Mr. Larry Tveit, you are State Senator of Montana?

Mr. **Tveit**. Right.

Mr. **Pickle**. Welcome, sir. And you are president of Montana Land Owners Association?

Mr. **Tveit**. I am a director.

Mr. PICKLE. We had scheduled Mr. Ken Luff, president of the Luff Oil Co. I understand that he is not here, and we have Mr. Robert S. Kerr III of Oklahoma City, who is going to testify for Mr. Luff. Are you part of the Robert Kerr family that served here in the Congress?

Mr. KERR. Yes.

Mr. PICKLE. Are you are grandson of Senator Kerr?

Mr. KERR. Yes.

Mr. PICKLE. He was something.

Mr. KERR. Thank you very much.

Mr. PICKLE. I knew him and loved to hear him talk, and he made a great contribution to this Nation, so we are glad to have you.

Mr. KERR. Thank you.

Mr. PICKLE. Then the National Association of Small Energy Producers, Mr. Hank Hankla, who is the Washington counsel for that group.

Mr. HANKLA. Yes, sir.

Mr. PICKLE. Mr. Anthony, would you care to make any statement about this panel?

Mr. ANTHONY. Thank you, Mr. Chairman. I would like to have the record make a special note that I have a constituent represented on the panel, Mr. Lindy Long, who has been a long-time personal friend of mine. I have worked with him very closely in trying to develop good energy policies and good tax policies. I am pleased that you would come up here, Mr. Long, and I welcome you before the committee. I am sorry that the schedule of other members did not permit them to be here, because I know that you will add a valuable contribution to this record and to the general debate on overall energy and tax policies that come to integrated companies, independent interests, and royalty owners.

Mr. PICKLE. I will ask Mr. Long to proceed and we will ask each of you to stay within your time confines, if you would.

## STATEMENT OF CHARLES "LINDY" LONG, PRESIDENT (PARTNER, LONG BROS. OIL CO.), ROYALTY OWNERS AND INDEPENDENT OIL AND GAS PRODUCERS ASSOCIATION OF ARKANSAS

Mr. LONG. Mr. Chairman, a lot of my testimony is repetitious, particularly in the last 2 or 3 days, so I will just summarize it.

My name is Lindy Long, partner of Long Bros. Oil Co., a small independent oil producer in Norphlet, Ark.

I am also president of Roark, the Royalty Owners and Independent Oil and Gas Producers Association of Arkansas.

We operate in south Arkansas, in what is known as the Smackover Field. Wells in our area average about 3,000 feet deep and cost an average of $1,000 to drill and complete. Nationwide one out of every 7 barrels of oil produced in the United States is pulled from stripper wells. In Arkansas, we have 97 percent stripper wells.

Arkansas, although not considered a large oil-producing State, is very dependent on the energy industry as most of the jobs in south Arkansas depend on the drilling and servicing of the wells.

Unless there is adequate incentive——

Mr. ANTHONY. Mr. Long, I have your testimony, so I can follow along with you, but if you could get the microphone up a little closer.

Mr. LONG. Is that all right?

Mr. ANTHONY. That is a lot better. The people in the back want to hear.

Mr. LONG. There should be adequate incentives to domestic oil producers. The Nation has a long way to go to reach energy independence. If the intangible drilling cost reductions were eliminated, I would only be able to drill half as many wells and maybe even fewer, and the U.S. Treasury would not make any more money. It would have twice the tax on half the oil.

In south Arkansas, there is 5 percent of the oil left in the ground and there is no pressure left to push it out. In fact, there is a negative pressure. Long Brothers can produce oil as cheap as anyone, yet several of our leases did not make a profit after the windfall profit tax.

Before January 1, 1983, when the windfall profit tax was still applicable to stripper production, the price of oil was $27.10 a barrel. Now, though the tax is repealed, we have had a $3 price cut in crude, which has taken away the advantage of the benefits that were served from the removal of the tax.

As of April 1, the price was $24.10.

It is hoped the Congress will keep in mind that it will be in the Nation's best interest to increase domestic oil production rather than increase oil taxes.

To force stripper wells to shut in is a terrible waste of our national resources. If stripper wells were abandoned and leases expired, it would not be economically possible to recover the remaining oil.

Above all, we must stop heaping abuse on the word profit. Profit is what motivates us and provides incentive for hard work. Profit supplies the capital for business expansion and new jobs. Profits are spread throughout the population creating wealth and jobs for a number of people.

Oil is extremely vital to the economy of our State. Arkansas produced 18,850,491 barrels of crued oil in 1981. In March 1983, the production was only 42,000 barrels per day which means we will have a decline of 3 million barrels of oil this year.

The 1981 tax laws must be maintained for the royalty owners and independent producers of stripper wells. A healthy industry means a healthy America to the future generations.

Thank you, Mr. Chairman.

Mr. ANTHONY. Thank you very much.

[The prepared statement follows:]

### STATEMENT OF CHARLES "LINDY" LONG, PRESIDENT, ROYALTY OWNERS AND INDEPENDENT OIL AND GAS PRODUCERS ASSOCIATION OF ARKANSAS

My name is Lindy Long. I am a partner of Long Brothers Oil Company and a small independent oil producer in Norphlet, Arkansas. I am also president of "Roark", the Royalty Owners and Independent Oil and Gas Producers Association of Arkansas.

We realize that the oil business is a complex business, and we are glad to have the opportunity to speak today and hope that what we have to tell you will help produce better energy tax policy.

We operate in south Arkansas, in what is known as the smackover field. Wells in our area average only 3,000 feet deep and cost an average of $100,000 to drill and complete. One out of every seven barrels of oil produced in 1981 was pulled from stripper wells and 97 percent of our wells in Arkansas are stripper wells. The wells that we operate average only (3) three barrels per day. Also, the crude in our area is a heavy gravity and is sour, so we cannot receive a premium price.

Arkansas, although by far not considered a large oil producing state is very dependent on the energy industry as most of the jobs in south Arkansas depend on the drilling and servicing of the wells.

In 1981, both majors and independents drilled 78,884 wells. The difference in a major and an independent as far as drilling activities can be seen with the following comparison. (Sources differ slightly in well count due to methods of data collection, but the following came from the Petroleum Information Corp. of Chase Manhattan Bank.)

| | New field wildcats drilled | Percent success wildcats | Total wells drilled | Percent success all wells |
|---|---|---|---|---|
| Majors | 809 | 22.4 | 8,657 | 82.9 |
| Independents | 8,522 | 18 | 70,227 | 64.4 |

In the U.S. there were 4,530 drilling rigs operating in 1981 as compared to the 1,834 operating today. The reduction is not only drastic to discovery and production, but also takes away 40,440 jobs that ultimately cause unemployment and welfare payments.

The National Supply Company, Houston, Tex. gives us other interesting facts. There is 11 to 12 tons of oil country tubular goods used per 1,000 feet of drilling each well. By the very nature of drilling operations, much of this steel must be left in the ground, whether or not the wells strike oil or gas. Almost 54 tons of Tubular goods were required for an average oil and/or gas well in 1981. By comparison, the steel in an average automobile weighed a little less than a ton. The decline of drilling has contributed also to the slump in the steel industry.

There should be adequate incentive to domestic oil producers. The nation has a long way to go to reach energy independence. If the intangible drilling cost deduction were eliminated, I would only be able to drill half as many wells. Maybe fewer. The U.S. Treasury would not make any more money. You would just have twice the tax on half the oil.

In south Arkansas there is 75 percent of oil left in the ground, and there is no pressure left to push it out. In fact, there is negative pressure. Long brothers can produce as cheap and as practical as anyone, yet several of our leases did not make a profit after the "WFPT". Before January 1, 1983, when the "WFPT" was still applicable to stripper production, the price of oil was $27.10. Now although the tax is removed, we have had a $3.00 price out on crude oil which has taken away any advantage of benefit that was received from the removal of the tax. As of April 1, the price is $24.10.

It is hoped that Congress will keep in mind that it will be in the Nation's best interest to increase domestic oil production rather than increasing oil taxes. To force stripper wells to shut in is a terrible waste of our natural resources. If stripper wells were abandoned and leases expire, it would not be economically possible to recover the remaining oil.

There is no other product on the face of the earth that can so control the American people and all the people of the world like energy. Our energy problem is not from lack of potential oil and gas resources still waiting to be found. The uncertainties created by confused and conflicting Government policies have diminished the economic incentive to search and produce.

Above all, we must stop heaping abuse on the word profit. It is profit that provides the incentive for hard work, profit that supplies the capital for business expansion and new jobs. Profit spreads throughout the population, creating wealth and jobs for great numbers of people.

In setting out to punish "big oil", thousands of individual Americans who by no measure are "big" in oil including many in Arkansas were hurt. The publicity had the passing of the "WFPT" as an attack on the profits of major oil companies, but in truth, the burden was carried by small royalty owners and independent producers.

Oil and gas is extremely vital to the economy of our state. Arkansas produced 18,851,498 barrels of crude oil in 1981. In March, 1983, the production was only 42,000 barrels per day which means that 1983 will have a decline of 3,521,498 barrels of production this year.

If tax policies can remain constant, there should be a gradual surge in the drilling operations. We care not only for our beloved state of Arkansas, but for the future of our country. We believe in the American economic system of free enterprises, and the American political system of individual freedom.

The 1981 tax relief must be maintained for the royalty owners and for the independent producers of stripping wells. A healthy energy system means a healthy America. The future generations depend upon it.

## STATEMENT OF LARRY J. TVEIT, MONTANA STATE SENATOR, AND DIRECTOR, NORTHEAST MONTANA MINERAL OWNERS ASSOCIATION

Mr. TVEIT. Mr. Chairman, and members of the Ways and Means Oversight Subcomittee, I am a State senator from Montana. I own and operate a farm and cattle ranch near Fairview in eastern North Dakota.

I appear before you today as a director of the Northeast Montana Mineral Owners Association plus other royalty associations in Montana representing their interests. There are several millions of acres of potential prospects to be developed.

The windfall profit tax that was applied to the royalty owners in 1980 was a very unfair tax because it put the royalty owner in the producer category. It nailed anybody that had oil producing property for the benefit of the Federal Treasury.

In 1981, I personally spent several days in Washington on three different occasions lobbying both the House and Senate Members on some kind of exemption for royalty owners and small independents in the Economic Recovery Act package of 1981. Some relief was given along these lines, one, phase back from 30 percent to 15 percent for newly discovered oil, two, independent stripper, and three, 2-barrels-per-day exemption for royalty owners. We were very pleased with Congress and the administration's action in granting this relief.

Our concern today is that we would like to hang on to those exemptions for the following reasons:

The phase back from 30 percent to 15 percent on the newly discovered oil—this encourages the industry to look for and invest in more exploration. This put big dollars to work nationwide. It helps boost local economies, provide thousands of jobs, take people off the unemployment roles and this, in turn, will, in the end, provide additional dollars to the U.S. Treasury.

The independent stripper exemption—this area is most important. The relief that the independents get now on these marginal wells is what keeps those 1- 3- or 7-barrel-a-day wells existing. If the exemptions were removed from these wells, thousands of wells could immediately be shut down because of the expense to keep them operating. In a lot of areas, excess salt water that is brought up with the oil has to be disposed of through truck haul or pipeline to disposal wells. The cost alone now with fallen oil prices is making these wells marginal.

I believe there is one thing we should all remember in this great free country we live in: that is that to remain strong and free is to be strong from within and that means less dependence on foreign crude. If these strippers were to close, it would mean hundreds of barrels of additional crude would have to be made up through foreign imports and further place us in a more weakened energy position.

The royalty owner barrel exemption—minerals are private property and the initiative and right to own private property is what makes this country of ours unique and strong. Look across the border and you will see Government ownership of minerals which in turn curtails development through typical government redtape and rules.

The royalty owner pays his full share of taxes, both State and Federal, and he or she should be taxed on as any other revenue income; but, to slap on a windfall tax, thus treating them as big oil, placed them in a very unfair position and does nothing more than to serve as a Federal ripoff of private property.

The barrel exemption for royalty owners was a big step forward in attempting to correct, I believe, a very unfair tax placed on royalty owners by the Federal Government. A large percentage of royalty owners are widows and elderly people on fixed incomes that received small royalty checks on their personal property. I do not believe the Federal Government should have the right to tax them excessively for that privilege.

I would encourage the committee to look forward on keeping these tax exemptions in place.

Thank you, Mr. Chairman, for allowing me to present my testimony.

Mr. Anthony. Thank you very much, Mr. Tveit.

## STATEMENT OF ROBERT S. KERR III, OKLAHOMA CITY, OKLA.

Mr. Kerr. Mr. Chairman, the area of interest to the committee I would like to address is the effect of the currently proposed Federal tax policies on private investment, in the independent oil and gas exploration.

I live in Oklahoma City, Okla., and currently am working as a business consultant. Until recently, I was employed as executive vice president of KEPCO, Inc., a small independent exploration company operating out of Oklahoma City, with overall management responsibilities, and the primary responsibilities for the security aspects of private placement investment offerings made by KEPCO, Inc., in furtherance of oil and gas exploration.

I maintain an informational relationship with KEPCO, servicing action that I brought to KEPCO during my tenture; prior to joining KEPCO in 1981, I was an investor in various independent exploration ventures, both before and during service in the Oklahoma State Legislature as a member of the Oklahoma House of Representatives.

As a freshman member of the house, I served as vice chairman of that body's Committee on Environmental and Natural Resources.

Prior to public service both as an undergraduate and law student, I worked in coordinating roles in three congressional races, two of which an old colleague of yours, former Congressman Ed Edmundson of Oklahoma when he was running for the Senate and then in 1976, the Fifth District of Oklahoma, the congressional race.

I am a life-long Democrat, and recently resigned as county co-chairman of the Democratic Party in Oklahoma County, as it is my intention to become involved in the Presidential elections this year.

My interests in giving testimony before the committee is threefold. First and foremost, as so many very astute and informative witnesses yesterday and today that I have seen, is to impart to the committee the importance Federal tax policy has on the life blood of small independent oil and gas exploration companies.

That life blood being investment capital obtained from private individual investors.

Second, I would like to impart my view that a strong healthy independent industry is of importance to our national energy industry and hence our country's security.

Finally, as I mentioned, as a partisan Democrat, I would urge the Democratic members of this panel to focus on the historic commitment our party has made to maintain the ability of small businesses to compete in our country.

Further, as it is my opinion that the small independent is engaged in as risky a business enterprise generally speaking as exists in our economy, I would hope and have confidence that the Democratic members of this committee and in the Congress would take special care to recognize that Federal tax policies in effect many impact the small independent in a substantially different fashion than the majors or even the large unintegrated independent.

KEPCO is not Exxon. Both play a contributing role in America's energy business. Repeal of current Federal tax policies might adversely affect Exxon. It could decimate a KEPCO and would be contrary to our party's longstanding philosophy of protecting and encouraging small businesses' ability to compete.

As referenced above, the life blood of the small independent company is its ability to attract investment capital, and frankly, in reality, due to well-tested security considerations as outlined by earlier witnesses, that money is obtained from individuals of substantial financial ability, people who have substantial personal incomes and are in a position to take advantage of the tax sheltering effect offered by current Federal tax law.

As I have mentioned, oil and gas exploration is a business involving a high degree of risk. Current tax policies recognize both the risk involved and the inherent value as it relates to national security embodied by an expanding domestic source of energy through the ability to, in essence, use some tax dollars in an exploration investment.

It is my considered opinion that if the tax incentives afforded in investment and exploration were withdrawn or reduced, those outside industries or independents currently investing in exploration would abandon such ventures as far too risky to warrant continuance, and it follows that an expanding source of extra industrial investment would become impossible.

This would leave the domestic exploration industry comprised of companies financially capable of risking large quantities of capital required for drilling for their own account. At best, this situation would substantially reduce an already depressed exploration climate generally, and particulary among independents, and at worse, permanently eradicate the ability of the small independent to conduct business, and hence cut off the opportunity for new individuals to enter the exploration business.

Coming from a family who has been involved in various aspects of the exploration business since the early 1920's, it has been my desire to obtain the requisite amounts of experience to enter the business on my own at some point.

I am afraid that if current Federal tax policies were to be altered, my ability to attract an investor base would be affected to the point that my ability to start a company could be totally eliminated.

I am sure that there are many other young people who are gathering experience working in and around the independent industry who share similar goals. In this vein, I would ask the members of the panel, in particular the Democratic members who I am sure share my belief in encouraging small business, to consider in depth what my experience tells me are the realities of attracting capital into independent oil and gas exploration.

Mr. Chairman, having been in public service myself, I believe I have some appreciation of the multitude of policy considerations that you must weigh in a search to find reasonable solutions to the financial problems facing the Federal Government. I would only ask that in your decisionmaking process, you give full consideration to the very special realities of the independent industry, an industry composed predominantly of small businessmen and small businesswomen, who contribute a great deal to the general security and welfare of the country.

Thank you very much.

Mr. **Pickle**. I thank you, Mr. Kerr.

Mr. Hankla is next, I believe.

## STATEMENT OF L. L. HANK HANKLA, ESQ., WASHINGTON COUNSEL, NATIONAL ASSOCIATION OF SMALL ENERGY PRODUCERS

Mr. **Hankla**. Good morning, Mr. Chairman, and Mr. Anthony.

My name is Hank Hankla. I am a practicing attorney here in Washington, D.C., and am appearing today as Washington counsel for the National Association of Small Energy Producers.

The National Association of Small Energy Producers is a new association on the scene in Washington, having only been founded in the spring of 1983.

On most issues, you will find everyone who is involved in energy from the smallest royalty owner to Exxon sharing the same concerns.

However, over the past 3 years as energy legislation has been debated vigorously by this Congress, it has become increasingly clear that changes in the Tax Code affect different segments of the industry to differing degress. Small producers want to insure that the Members of Congress who must decide these issues, have the most accurate information possible on what impact any particular proposal will have. In that regard, I am privileged to testify here on this newly formed organization today.

Others on our panel have spoken more specifically about the concerns of stripper well operations, royalty owners and independents who rely on private investors for their drilling capital. I want to address the larger picture—the policy issues.

If after these hearings are concluded, the Ways and Means Committee should attempt legislative changes in the Tax Code, there can be only two objectives:

First, to change who it is who drills for oil and natural gas in America; or

Second, to change the amount of revenue flowing to the U.S. Treasury.

As to the first, we are really asking, "What is the best tax policy for small businessmen whose business is oil and natural gas exploration and production?" Certainly, this is a capital intensive industry. Even a small energy producer may raise and spend several millions of dollars each year; however, when compared to Texaco or Exxon this producer is relatively smaller than is the corner grocery as compared to Giant Food, or the local restaurant compared to McDonald's.

Moreover, a small producer lives and dies by his ability to convince others to invest their money with him. Any changes which would eliminate or reduce the value of Tax Code provisions such as the intangible drilling cost deduction or the percentage depletion allowance, would choke off the flow of the small producers' life blood. Without this invested capital, the small producer will be forced to drill few, if any, new wells.

According to the February 15, 1983 edition of World Oil magazine, independents drilled 88.4 percent of the wells drilled in 1982 in America. In certain areas the figure is much higher. For instance, in my native Oklahoma, independents drilled 95.87 percent of the 1982 oil and natural gas wells.

If Congress should eliminate the provisions which now encourage doctors in New York or lawyers in Boston to invest with independents, the immediate result will be a big shift in the percentage of wells drilled by independents. We could expect the majors to continue to drill at their historic level because they finance their operations with internally generated capital.

However, if independents' drilling fell by at least 50 percent—as it is anticipated it would if IDC's were eliminated—the percentage or production controlled by major international integrated oil companies would jump.

If the social policy this committee believes is best for America is to significantly increase the control that major oil companies have over American energy production, then you should eliminate any differential tax treatment for independent oil and natural gas producers. If the preferred social policy is to encourage competition and small business, the current tax provisions should be preserved and expanded.

On the second point, I urge you to reject the counsel of those who say we can reduce the deficit by closing the loopholes which currently benefit independent oil and natural gas producers. My survey of this indicates that the Treasury would not increase its revenue $1 by repeal of any of these measures. The result would only be fewer wells drilled as investment dollars are rechanneled into real estate or Cleveland municipal bonds or other investments.

Increasing the tax on fewer wells does not increase the Treasury's revenue.

More specifically, I urge you to reject the numbers generated by the computer models used by the U.S. Treasury, the Joint Tax Committee, and the Congressional Budget Office. On these measures, all of these analyses are based on what is known as a static revenue production model. Basically, this model sets an established level of economic activity—in this case, the level of activity in the oil and gas business for a previous year. The value of a specific tax provision is then measured—in this case, the tax not paid because of the existence of the depletion allowance, for instance. Then that value is converted into a figure that is supposed to represent the increased dollars that would flow to the Treasury if that Tax Code provision were repealed. Their model does not figure in any change in the level of economic activity occurring because of the change in that Tax Code provision.

The CBO estimate we heard yesterday was that there would be $8.7 billion raised over 5 years if the depletion allowance were repealed, and $15.3 billion raised with the repeal of the intangible drilling cost deduction.

Mr. Chairman, those are phantom numbers. Their numbers will not be accurate and that money would not be raised.

Should you expect to raise revenues by repealing these sections of the code, the only result is that this committee will be back here next year trying to figure out another way to generate that expected revenue.

In summary, I urge you to view the Congress role as the people's investment bankers. Each change in the Tax Code encourages capital to flow into certain channels more than others.

Congress decides [illegible] capital should flow into certain channels more than others. [illegible] capital flows down these channels, it gets used to make something [illegible] happen which Congress, in its wisdom, has determined would [illegible] happen—or will not happen to a desired degree—if left to the [illegible] market. Congress has in the past made such decisions to encourage capital to flow to charitable organizations, to the building of low-income housing and to the rebuilding of our heavy industry.

Members of Congress have a clear choice: If you believe in the flat tax and the so-called level playing field, you should encourage the elimination of sections of the Tax Code that favor independents. In so doing, you will know that you have made the decision to drastically reduce the number of small producers who can remain active in this business. In doing so, you will concentrate energy production in the larger business.

On the other hand, if you vote to keep and expand the tax provisions which are currently applicable to independents, you will be voting for small business and for energy independence.

We urge your continued support of small energy producers.

Thank you.

Mr. PICKLE. Thank you, Mr. Hankla.

I thank all the panelists. I am going to take advantage of my position here. Mr. Anthony welcomed Mr. Long here, who is a personal acquaintance. I am glad he did. We take that privilege on occasion.

I don't know Mr. Kerr, but I know his family. Your grandfather was a member of the U.S. Senate at the same time as then Majority Leader Lyndon Johnson. Lyndon Johnson was my political mentor and my good friend, and he was a great person, regardless of what some authors might write. He and your grandfather were quite a pair, and I am proud to recall the many things they have done for the Nation, and I am particularly pleased to get to say to you that we appreciate your grandfather's service.

I think we understand your situation, your concern, of small business, which would include the royalty owners. I hope the Congress can maintain that commitment that we made.

Any questions from the members?

Mr. **Anthony**. Mr. Chairman, I have quickly pencilled out some numbers based on the testimony of Mr. Long, to try to emphasize that in regard to the State of Arkansas, any change in tax policy could not come at a worse time.

On page 2 of your testimony, you show where the price of oil has dropped from $27.10, as of April 1, the posted price, to $24.10. At the bottom of the page you talk about production in Arkansas in 1981, a little over 18.8 million barrels, and what it is averaging now, 42,000 barrels per day. In 1981, it turns out to be 51,648 barrels per day.

If you do some arithmetic, you see we have about 9,000 barrels a day less, and if you add the drop in price, you can see that we have $216,000 less revenue flowing through the economy in Arkansas.

And I am sure this story could be told many times over in Montana or Oklahoma. Mr. Hankla represents producers from many States. So, if we don't do anything else, hopefully we can set the record straight. This is an industry suffering from price and other policies, both domestic and foreign. So even if people believe tax policy ought to be changed, this would be a terrible time to do it. On the contrary, it would be compounding a difficult circumstance.

I just want to commend you for bringing those figures out so that at least one State could have on the record how difficult it would be if something they had been promised and is currently in the code is either frozen or repealed. I think you have made a valuable contribution to our subcommittee.

Mr. **Pickle**. Mr. Dorgan.

Mr. **Dorgan**. Thank you, Mr. Chairman.

I appreciate the fact that you were willing to participate in the hearings. I think it is important to point out again, as we did yesterday, that there is no hidden agenda here. We are simply interested in creating a record on what the tax consequences are for the independent oil producers of America and trying to analyze what that means. The contribution you have made and other witnesses have made have been substantial.

We appreciate that.

Mr. **Pickle**. Thank you all very much for appearing before us.

All your statements will be included in the record.

The Chair is going to combine two panels. Mr. G. E. Stahl, president, National Stripper Well Association, and Mr. E. L. "Bud"

Stewart, Jr., representing the Energy Consumers and Producers Association of Oklahoma, please come forward.

Then I am going to ask another panel to join these two gentlemen.

Mr. Don Hupp, a CPA, representing the North Texas Oil and Gas Association, and Mr. Dennis Purdum, who represents the West Central Texas Oil & Gas Association. And then Mr. Thomas R. Cambridge, of the Panhandle Producers and Royalty Owners Association.

I particularly want to welcome this panel because there are several witnesses from the Texas area, as well as Oklahoma.

Mr. Stahl, you may proceed.

## STATEMENT OF G. E. STAHL, PRESIDENT, NATIONAL STRIPPER WELL ASSOCIATION

Mr. Stahl. Thank you.

I am an independent operator from Amarillo, Tex. I am appearing here as president of the National Stripper Well Association.

I am not going to read the prepared remarks, but I would like to make a couple of rather brief but important points.

Stripper wells in this country produce one barrel out of every seven. We produce 13 percent of the oil that is produced in the country.

More importantly, we think 74 percent of the wells that pump in this country are stripper wells. That represents something more than 400,000 producing wells.

Specifically, I am going to address myself to one specific issue relative to these hearings. That is, as you all know, the windfall profit tax was eliminated effective January 1, 1983, with respect to the independent segment, with respect to stripper oil.

Now, stripper oils are different than the other part of the oil industry.

Unless that is understood, then the implications of increasing the tax, returning the tax, or putting a substitute tax in place of the windfall profit tax cannot be fully understood.

We are the low end of the oil industry. We are the least economic. The average stripper well in this country produces something like 2.85 barrels a day, less than 3 barrels a day. Out of that, we have certain minimum operating expenses that we cannot avoid. Those operating expenses are basically enumerated in this testimony.

The point is, that if you adversely increase the economic adverse impact on a well by any fashion, whether this is an increase in taxes, a decrease in the price of crude, an increase in operating expenses, you automatically cause the plugging of a certain strata of wells, and it is our position that anytime that you adversely impact on a well, you cause premature abandonment of that well, that oil production is lost to this Nation forever, and it must be replaced by a barrel of foreign crude that has to be purchased from a foreign nation.

In our judgment, that is bad, and that is not a policy that should be fostered by the Congress of the United States.

I would address myself, gentlemen, rather briefly to a couple of points I heard this morning by Mr. McIntyre.

By listening to Mr. McIntyre, although he was commenting upon my segment of the business world, to wit, being an independent producer, it is obvious to me Mr. McIntyre is not an independent producer; I will guarantee you that. Anybody that says to you that on a long period of time, you can take and invest $2 and only find $1 of return does not understand the economics of the independent segment of the oil industry; I can guarantee that. Tax considerations or no tax considerations, no one can do that for any protracted period of time.

The independent segment of the oil industry, and particularly my part, the stripper well segment, is intensely conscious of economic return. That is our whole point.

You eliminate through tax policy some of our economic return; you guarantee that we plug wells.

That is our whole pitch to this committee. It is with the consideration that the elimination of the windfall profit tax as of the first of the year was sensible tax policy.

To reinstate it or substitute would be disastrous tax policy.

[The prepared statement follows:]

## STATEMENT OF G. E. STAHL, PRESIDENT, NATIONAL STRIPPER WELL ASSOCIATION

Chairman Rangell, Members of the Committee. My name is G. E. Stahl. I am appearing as president of the National Stripper Well Association. By way of background and explanation, a stripper well is an oil well that produces less than 10 barrels of oil per day. The 1981 average per well production from the stripper wells in the United States was 2.85 barrels per day. (The 1981 figures are the lates that have been compiled.)

Stripper wells account for 13 percent of the total U.S. production or 1 in every 7 barrels produced, this is not an insignificant amount of production. More importantly, 74 percent of the wells producing in the country are stripper wells or slightly more than 400,000 wells.

Stripper wells have historically been treated by Congress in a favorable light ever since Congress has enacted legislation directly impinging on the oil industry.

My purpose is to present persuasive factual evidence to you that such favorable Congressional treatment is justified and that such treatment has, in fact, accomplished the intent of Congress. Such favorable treatment accorded the stripper well segment of the oil industry is predicted on the assumption that Congressional intent was basically to:

(1) Preserve an economically viable stripper well industry.

(2) Not to cause the premature abandonment of any oil well regardless of the small amount of oil it is capable of producing.

(3) Maximize the economic benefits the stripper well industry contributes to the general economy which, in turn, maximizes the number of jobs, goods and services which flow through the national economy as a result of income which flows from a stripper well to the economy.

The stripper well segment of the oil industry is different from the rest of the oil industry in two basic ways:

(1) Many of the stripper wells are operated by a multiplicity of independent operators, most of whom are small in the scope of their operations. They operate in a relatively confined geographic area. They range in size from the one man oil operator to a modest size operation but when compared with the major oil company segment of the business are extremely small.

(2) Stripper wells are at the bottom end of the economic scale of the oil industry. This single fact, that they are small producing wells, makes them the most vulnerable to any adverse economic impact.

Consequently, any factor which has as adverse economic impact on the stripper well portion of the industry hastens the day that the lowest strata of producing wells will be prematurely abandoned and will be plugged. That production is then lost forever to the operator and more importantly to the nation and must be replaced with imported oil from a foreign source.

To be specific, a stripper well produces a certain daily income to the stripper well operator. From that income, the operator must pay at least the following items of expenses:

(1) Royalty to the landowner.
(2) State production taxes and state property taxes.
(3) The wages of the field people he hires to look after the well.
(4) Operating expenses, such a electricity, water hauling.
(5) The necessary well maintenance expenses to keep the well producing.
(6) The salaries and office expense incurred in running an oil business.
(7) If the property is financed, paying back the bank or other financial institution.
(8) Something left over for the operator to compensate him and to permit him to reinvest in additional oil properties.

With the exception of the last item, all of these must be paid if the well is to continue to produce. At such time as the income from a well is not sufficient to cover these items of expense, the well is plugged. This is a harsh economic fact.

One single factor influences the decision to plug a well. This is a decrease in income. Such a decrease results from either a drop in the price of crude oil, or an increase in operating expenses. Once a well reaches the point in its economic life where out-go exceeds income, the well is plugged and abandoned.

You will note that I did not include any taxes paid to the Federal Government in the detail of expenses to be paid by the income from the well.

Obviously, Federal Income Taxes are attributable to the net income after expenses. Any additional, or new tax, imposed by the Federal Government is an additional operating expense and it, by itself, will casue the lowest strata of stripper wells to be prematurely abandoned.

As you are aware, the Windfall Profits Tax was eliminated on stripper oil produced by Independent Operators on January 1, 1983. If reimposed in any fashion, the only result will be to hasten the abandonment of otherwise produceable oil.

In our judgement, such a course of action is inadviseable and contrary to the best interest of the nation. The ripple effect of the income from a well that is maintained in production is substantial.

The salary I pay my field man is spent by that man to feed and clothe his family. That ultimately goes to the corner grocery store. If I must prematurely abandon a sufficient number of wells, I can no longer keep that man gainfully employed. While that may be a disaster to him and to me, in the larger sense, it is a disaster for every entity in the chain that receives benefit from the income which flows from that well. The oil production that is thus lost forever must be replaced by oil purchased from a foreign source. I submit the ripple economic effect of oil produced from a foreign source does not benefit the domestic economy but in fact is to the long term detriment of the U.S. economy.

If the policy of the Congress is to preserve and create jobs and to create an environment where the nation can maximize domestic oil production consistent with other national goals, then the imposition of any Federal Tax on the stripper well portion of the industry will defeat those goals.

Let me point out that no oil operator ever starts out to drill a stripper well, but that every well drilled will ultimately become a stripper well unless plugged and abandoned before it reaches a level of less than 10 barrels per day.

In conclusion, I would point out that the factual data available proves beyond any doubt that the policy of special consideration to the stripper well segment of the oil industry works to accomplish the purpose intended. I will not bore you with statistics other than to say the 1981 figures we have prove that the number of stripper wells still producing increased, that the total production from stripper wells increased, that the number of wells plugged declined. The 1982 figures are not compiled, but the preliminary statistics from the primary stripper wells states including Texas, Oklahoma, and Kansas, indicate that the trend continued in 1982. The elimination of the Windfall Profits Tax on January 1, 1983 will accelerate the positive effect for 1983 even though the price of crude oil has decreased in the U.S.

We believe Congress gave the stripper well operators a mandate and we have responded to accomplish that mandate.

Mr. PICKLE. Thank you, Mr. Stahl.

I noted that you have concentrated on the stripper aspect. I am glad you made this point.

Now, we will hear from Mr. Bud Stewart, representing the Energy Consumers and Producers Association, Seminole, Okla.

## STATEMENT OF E. L. "BUD" STEWART, JR., PRESIDENT, ENERGY CONSUMERS AND PRODUCERS ASSOCIATION, SEMINOLE, OKLA.

Mr. STEWART. Thank you very much, Mr. Chairman. I appreciate the opportunity to appear here and also to have my statement submitted for the record.

I have been in the oil and gas business since 1951, 10 years of which was with a major company, and the rest of that time an independent producer.

Our association is made up of some 800 independent small operators residing in some 35 States—Arkansas, Texas, Oklahoma, all included.

I do not want to repeat a lot of the testimony I heard yesterday and today. But I would rather discuss some points in my testimony as well as some that were brought up by others.

First of all, I think one thing that needs to be perfectly clear—as you look historically at the oil and gas business in this country, you will find there is an absolute parallel between the total number of wells drilled and the daily average production and reserves found.

You can correlate that the more wells you drill each year, that there will follow in a year or two an increase in the daily average production, and also an increase in reserves. Granted oil and gas is a finite resource, and increases perhaps are not going to happen forever, but it certainly has happened up to this point.

So, I think it is important to recognize that the Congress, through its tax policies, and the Federal Government, through any energy policy, needs to recognize the importance of getting as many wells drilled—dry holes, wet holes, gas, oil, whatever—get as many wells drilled as possible. And I think the IPAA brought up a good point in testimony yesterday. They say in order to stay even on imports, where we are, plus a slight increase in oil demand over the next 10 years, we need to drill 890,000 wells. Now, keep in mind that in 1981 we drilled more wells than we have ever drilled in the history of this country. That was 84,000 wells. So we are talking about over a 10-year period drilling 5,000 more wells per year than we have ever drilled before, just to stay even.

In this morning's Washington Post, there is an article that the Energy Information Agency has come out with a forecast, and they state that even though our import level today is 4 million barrels per day, they predict an increase in demand because of recovery, et cetera, that by 1985, we are going to be importing 7 million barrels a day.

We now produce 8 million, roughly, barrels a day. So that means that if the Energy Information Agency is halfway correct, that we are going to be very close to the level of imports we were when we had the embargo in 1973. We are going to get up in the midforty percent on imports of crude oil if we maintain what we are doing now. I don't think that the Congress wants us to be more dependent on foreign sources for oil supplies.

I am sure the members of this panel, and this industry, don't want us to be dependent.

Another point I think is clear: I was involved in all the legislative fights for the past few years. I remember many government officials in various congressional hearings said there is no more oil or gas to be found; we are running out. I remember when I first started in 1951, we only had 13 years' natural gas supply left, and something like 15 years of crude oil supply left, at then present levels of production. So, that ratio really has not changed over the years. The whole key is to drill more wells. And I think for at least the foreseeable future, we are going to find more oil if we increase drilling.

I would like to discuss just very briefly where are we going to get the funds as independents and even as majors to drill an average of 89,000 wells per year.

In my testimony it shows Chase Manhattan Bank has done a study. If nothing changes, Chase predicts the independent segment of the industry percentagewise is going to expend less for exploration. They are going to have to go to other sources, primarily internally, to raise the capital if they are to participate in expanded exploration.

Independents cannot go internally. We have got to make it more attractive to go to external sources if we are going to be a part of the 89,000 wells which need to be drilled and maintain our present percentage level of expenditure. We need no new taxes at all, repeal, whether it is just for the independents or majors; I think it ought to be for everybody—repeal the windfall profits tax as soon as possible. Return to the 27½-percent depletion allowance. Eliminate the minimum tax aspects of the IDC's. Then I think we will possibly have the type of tax structure which perhaps will enable us to drill 89,000 wells per year, if that is what we want to do.

Mr. DORGAN. May I interrupt you just a moment? In one of the recommendations you suggest repealing the windfall profits tax. Would you require a plough-back if you do that?

Mr. STEWART. I would not object at all. If you can figure out how to administer it.

Mr. PICKLE. Mr. Stewart, I thank you. I appreciate your testimony. It is good for us to be reminded, if we go for that 7½ billion barrels, we are now up to the 11 million-plus, we have to drill 890,000 wells?

Mr. STEWART. In 10 years. That is IPAA's figures.

Mr. PICKLE. That is hard to believe, isn't it?

[The prepared statement follows:]

## STATEMENT OF E. L. BUD STEWART, JR., PRESIDENT, ENERGY CONSUMERS AND PRODUCERS ASSOCIATION, SEMINOLE, OKLA.

Mr. Chairman, members of the Subcommittee, I am E. L. Bud Stewart, Jr., President of the Energy Consumers and Producers Association from Seminole, Oklahoma. The ECPA has some 800 members who are independent oil and gas operators, producers, or royalty owners residing in 35 states of the Union. Few, if any, of the ECPA membership own any interests in pipelines, refineries, marketing outlets or offshore production. For the most part ECPA members have no more than 2 to 20 employees. Thus, these people are truly small independent businessmen and women.

As I am sure members of the Congress know, the boom times of oil and gas drilling of 1981 have disappeared in a flood of red ink and Chapter 11 bankrupcies. The number of drilling rigs employed today is 56.8 percent less than 15 months ago. Like any industry which idles over one-half of its primary productive capacity, the downturn translates into the loss of thousands of jobs. Also, like any industry when plants are closed, many other thousands of employees in supply and service companies suffer loss of jobs.

Unemployment rates in many oil and gas business centers far exceed the national average—in Texas, Houston at 10.5 percent, and Port Arthur at 21.3 percent and Elk City in rural Oklahoma at 11.8 percent in February are but a sample of the widespread decline of the industry.

However, unlike most other industries currently suffering plant closings, the product not produced by the idle rigs—crude oil can only be acquired from foreign sources to meet the minimum needs of the country. Unfortunately, much of the imported crude oil originates in the unstable Persian Gulf area. While the U.S. has made remarkable strides in oil conservation in recent years and overall oil demand is reduced, approximately 4,000,000 barrels of oil and products are imported daily which constitute over one-third of total national requirements. This need not be. The domestic oil and gas industry has the knowledge and skill to reduce and ultimately eliminate all crude oil imports. However, to eventually eliminate imports, federal government policy must be altered to encourage additional drilling.

For many years and before several committees of the Congress, ECPA has stated that a sustained drilling rate of over 80,000 total wells per year would reverse the precipitous decline of production and reserves and indeed would increase supplies. (See Chart I). Drilling rates have steadily increased from a low of 25,000 wells in 1971 to over 85,000 wells in 1981. Even though only once has the total annual number of wells drilled been over 80,000 the decline in oil and gas reserves has been virtually halted, and just when the drilling slump occurred, the industry was poised to actually increase reserves. (See Chart II). In my opinion, this recovery was no small accomplishment given the fact that both oil and gas reserves were depleting at a rate of 7 percent to 10 percent per year. Also, I would hasten to remind the Committee that in the mid-1970s many government officials repeatedly testified there were no significant additional reserves to be found domestically. Surely the several large discoveries of late have proved the error of their expertise.

It is a recognized fact that governmental priorities influence governmental tax policies and tax policies tend to make things happen, or as the case may be, not happen! For many years Congress encouraged capital to flow to the oil and gas industry by granting depletion allowance of 27½ with certain limitations. Currently the depletion allowance has been eliminated altogether or reduced by aproximately one-half for small producers. For many years Congress encouraged added drilling by not subjecting intangible drilling costs to minimum taxes. Currently important segments of the drilling industry pay a minimum tax on normal costs of doing business. Prior to the enactment of the so-called "windfall profits" tax, Congress allowed the oil industry, like any other industry, to invest the proceeds of its business as it deemed best with tax consequences based on its profit or loss. Currently the "windfall profits" tax diverts gross proceeds of sales from the industry on 88 percent of the total barrels of oil produced in the lower 48 states. Thus, apart from any social and political benefits the "windfall profits" tax may render to the citizens of the nation, the tax results in fewer wells being drilled, less domestic employment, and an outflow of dollars to pay for imports most of which would be produced in the U.S. The "windfall profits" tax impacts especially hard on the small independent producer whose sole profit center is production from wells. There are no "upstream" operations to look to for any recovery of even a portion of the tax.

The domestic recent decline in oil and gas exploration and development has several causes. The general decline in the economy is certainly one cause. The instability of the price of crude oil and the fear of a dramatic price downturn should receive a share of the blame. Also, of considerable importance has been the reduction of the maximum individual tax rate from 70 percent to 50 percent which has diminished the attractiveness of oil and gas investment in competition with other investment opportunities. Widespread publicity in recent months that the oil and gas industry may be saddled with additional taxes has tended to discourage badly needed capital from coming to the industry.

Historically the independent operator has drilled some 85 percent of the wildcat wells in the country; found a majority of the new fields; and, produced over one-half of the oil each day in the lower 48 states. Thus, the independent is an important element in the energy security of the country.

The Chase Manhattan Bank's Energy Economics Division completed studies published last November in the Oil and Gas Journal devoted to the future funding requirements of the petroleum industry under several sets of circumstances. To maintain production at current levels will require ever increasing expenditures by both major companies and independents. According to Chase the sources of the increased funds will tend to be raised internally rather than from external sources. Internal funding of necessity favors the major companies. Even though independents accounted for 32 percent of exploration and production expenditures in 1980, it is predicted the independent share will be reduced to 29 percent in 1990. (See Chart III). Even so, independents will require over $31 billion in capital to maintain a lower total share. If independents maintain their 32 percent share of exploration and development in 1990, the required funds would exceed $35 billion. This would equal over three times the $10 billion expended in 1980. If independents maintain the same relationship between external and internal funding sources in 1990 as in 1980, almost $24 billion needs to come from external sources which is exactly four times the amount raised externally in 1980. (See Chart IV).

Obviously, to accomplish raising increased funds of the suggested magnitude, the investment community must have increased confidence that public policy will encourage additional investment in oil and gas exploration.

Thus, ECPA recommends public policy be directed toward:

(1) Reducing the need for imported energy by increasing production from all forms of domestic energy resources.

(2) Increase the incentives for individuals to participate directly in natural resource exploration and development.

ECPA suggest the following to be considered as incentives for individuals and corporate independents to invest:

(1) No new taxes be placed on the industry.

(2) The "windfall profits" tax be allowed to expire at an early date.

(3) The percentage depletion allowance be returned to its 1970 level of 27½ percent.

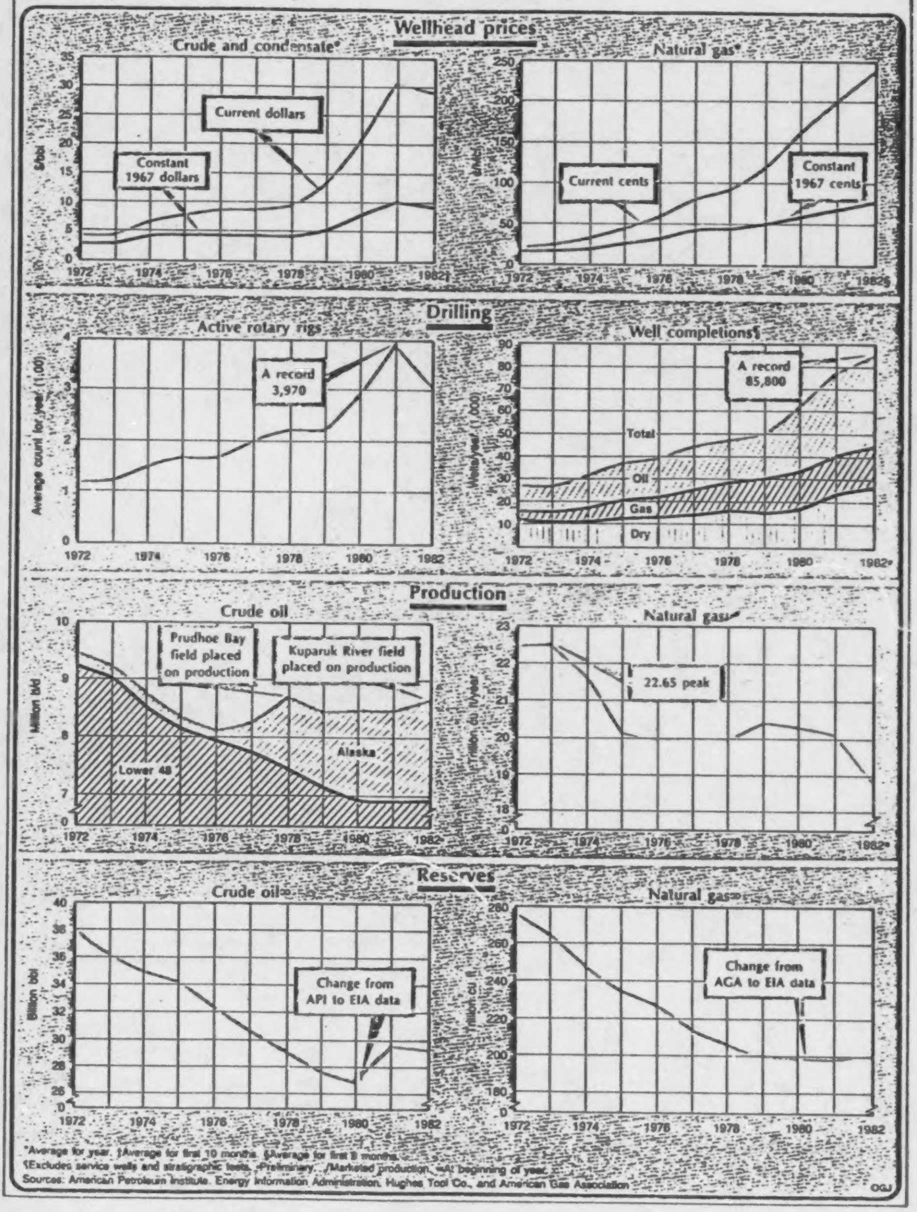
(4) Intangible drilling costs be considered a business expense not subject to minimum tax consideration.

I would be pleased to attempt to answer any questions.

CHART I

The exploration/development scene in the U.S.

Fig. 2



*Average for year. †Average for first 10 months. §Average for first 8 months.
¶Excludes service wells and stratigraphic tests. ·Preliminary. ‚Marketed production. ∞At beginning of year.
Sources: American Petroleum Institute, Energy Information Administration, Hughes Tool Co., and American Gas Association

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CHART I

CHART II

Fig. 1

Oil reserves additions vs. drilling

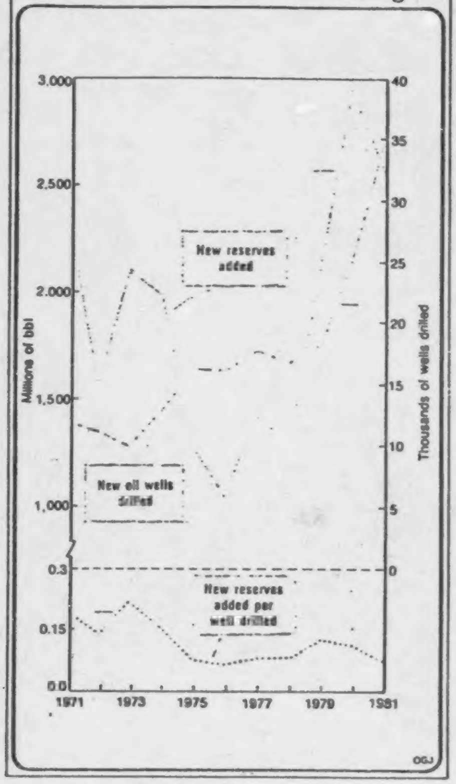

Fig. 2

Gas reserves additions vs. drilling

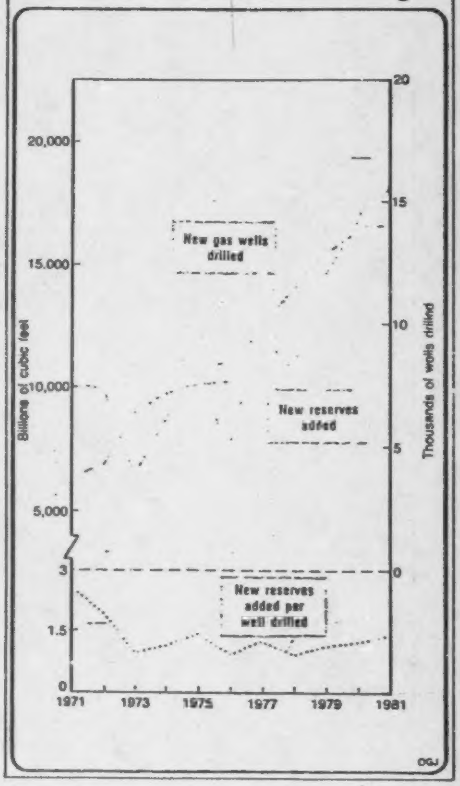

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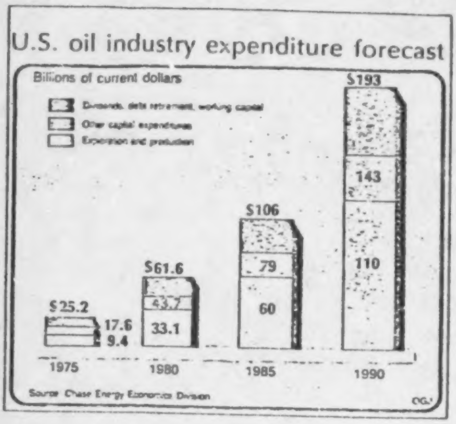
CHART II

CHART III



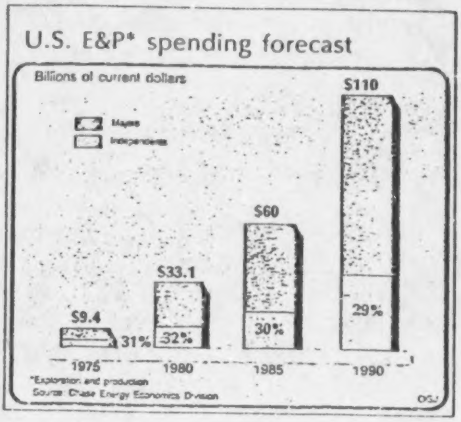


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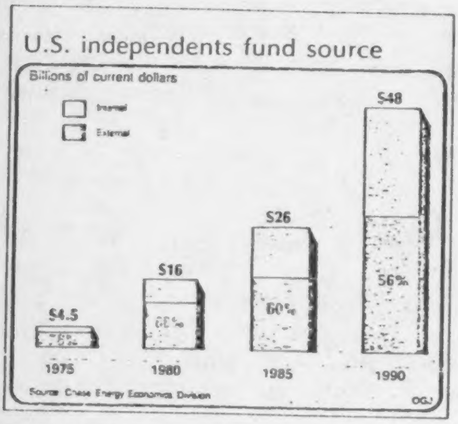
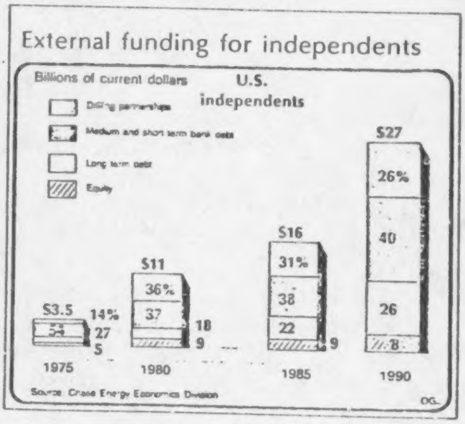
CHART IV





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Mr. Pickle. Now, I am going to ask Mr. Don Hupp to present his statement.

Mr. Hupp, we are glad you are here. The majority leader, Mr. Wright, asked us to be sure that you are properly welcomed. We are pleased to have you here.

## STATEMENT OF DON HUPP, CPA AND CHAIRMAN, TAX COMMITTEE, NORTH TEXAS OIL & GAS ASSOCIATION

Mr. Hupp. I am a certified public accountant in Wichita Falls, Tex. As a member of the North Texas Oil & Gas Association, I serve as chairman of the tax committee.

North Texas is a 15-county region referred to as Texas Railroad Commission District IX, with a population of approximately 420,000. The economy of this region relies greatly on the petroleum industry and is dominated by the independent producer.

North Texas oilfields are mature. Annual production declined over 50 percent from 1965 to 1979—74 million barrels in 1965 to a low of 33 million barrels in 1979. However, due to the net increase in the price of oil, we have seen a dramatic turnaround, and production has actually increased since 1979—from 33 million barrels in 1979 to 37 million barrels in 1982. The average daily production per well of the 34,500 wells in north Texas is 2.9 barrels compared to the statewide average of 14 barrels per day. Future oil production will be derived from marginally economic properties with low recoverable reserves.

Obviously, to maintain this production, these properties must be operated efficiently with strict cost control which historically the independent producer has done through diligence and daily attention to the properties. Due to economics, maintenance of the current level of production is a very difficult task and can only be achieved in an environment which encourages those efforts.

In north Texas, 90 percent of the wells are stripper wells, of which 80 percent are operated by independents. The independent oil and gas producers in our area are in business today producing these wells which others have considered played out. One major reason for this is the tax incentives which encourage the development of small reserves and continued production of marginal properties; a critical element in our overall energy picture.

The typical north Texas independent is very close to the production process; that is, he functions as the geologist, engineer, and production supervisor. He makes the decision to drill a development well or work over a producing well. He is the proprietor, and his decisions affect him directly. Most independents are constantly reinvesting earnings in an attempt to increase reserves.

Many of my clients are independent producers, and I can tell you most assuredly that tax incentives have, over the years, increased their exploration level. I see and counsel on these decisions daily.

I can also tell you that, should depletion and IDC deductions be curtailed further, many of my clients will be forced by economics to cut back or halt exploration. A 5,000-foot well in north Texas costs approximately $200,000 to drill and complete. This is a considerable sum for independents in our area to risk.

Tax incentives as currently provided to the independent are limited and only provide a base upon which he may develop reserves. Once that production base has been exceeded, the incremental production is taxed at rates comparable to nonindependents, and in the case of individuals at higher rates.

I would like to take this opportunity to bring to your attention a matter which I believe has been overlooked. I strongly encourage you to consider altering the tax laws to provide a stimulus for an independent to purchase marginal properties from a major oil company.

As the current law is written, the windfall profit tax stripper exemption and statutory depletion provisions which help an independent keep marginal properties producing cannot be used if that property was previously owned by a major oil company. To avoid premature abandonment of marginal wells by majors, I believe some incentives should be enacted to insure marketability of these wells to independents. In my opinion, to avoid this issue does not meet the test of reason.

Increased taxes take capital from the industry, just like lower prices. History has proved again and again that domestic oil and gas production is directly related to economics; this fact has been recognized by Congress in the past through tax incentives.

To reverse position and take away basic incentives as they exist today will have grave repercussions, and is not in the best interest of the Nation. Without the independent, the small reserves will not be searched for, developed, and produced. These barrels must be replaced somewhere.

The dual needs of domestic energy development and increased tax revenues can best be served through a tax structure which promotes a healthy domestic oil and gas industry. A tax program which accomplishes this also benefits steel, chemicals, and other basic industries nationally.

I will be pleased to answer any questions you might have regarding specific tax considerations and how they affect my clients or typical independents in north Texas.

Mr. PICKLE. We thank you.

I had not given much thought to the fact there is no stimulus for an independent to purchase marginal properties from the majors.

We will look at that aspect.

Now, Mr. Purdum.

Where is your home?

Mr. PURDUM. Houston, Tex.

Mr. PICKLE. All right.

## STATEMENT OF DENNIS PURDUM, MEMBER, TAX COMMITTEE, WEST CENTRAL TEXAS OIL & GAS ASSOCIATION

Mr. PURDUM. Thank you, Mr. Chairman, members of the committee.

I am a partner with Arthur Young & Company, and presently director of taxes in our Houston, Tex. office.

My testimony here today is presented on behalf of the more than 1,000 members of the West Central Texas Oil & Gas Association. West Central Texas Oil & Gas Association represents independent oil and natural gas producers who, for the most part, are small businessmen involved in high-risk business.

You are inquiring about the extent to which the present tax law favors independent producers, whether tax treatment which is not uniform is good tax and energy policy, and whether the specific provisions to provide differing treatment work as they were intended.

To this we answer "Yes." There are provisions of the law such as percentage depletion, intangible writeoffs and lower windfall profit tax rates which are different between majors and independents. However, the very nature of our businesses is different. The oil business inherently is capital-intensive. The major companies have access to many different capital markets, but the independents are limited to attracting risk capital.

Is tax treatment which is not uniform good tax and energy policy? Tax laws in general are not uniform. Oil and gas has always been treated differently than other businesses. However, the independent producer tax treatment is very similar to other natural resources which also have percentage depletion and writeoffs of exploration costs.

For example, percentage depletion is allowed for coal, sulphur, uranium, gold, silver, and copper. These incentives are designed to encourage the search for these depletable assets. As for the best energy policy, we feel that the best policy is one that encourages domestic exploration and self-sufficiency within the United States.

The most important question for us to answer is whether these incentives are working. We feel that they are working. In order to survive, the independent must be able to raise risk capital. The tax laws are written so that the independent and his investors can reinvest money back into the search for new oil and gas. And that's only fair: America needs domestic oil. So, why not let Americans search for it with funds they have earned from previous discoveries?

These incentives must be working. The independent oilman drills approximately 90 percent of the wells in the United States, and he historically reinvests 105 percent of his gross wellhead revenue back into the exploration for new reserves or development of those reserves they have already found.

Why do independents and their investors drill such a high percentage of wells, and reinvest their revenues back into the search for reserves? Because the incentive is still there that if they do find significant quantities of oil or natural gas, then they will profit.

Independents cannot survive without raising money from outside investors. If we take away these incentives, they will look for more conservative investment. Exploration for oil and natural gas is a risky business; chances are but 1 in 10 that an exploratory well will be a commercial productive well.

The stripper well exemption to the windfall profit tax can easily make the difference between a well being plugged or continuing production. Stripper wells are costly to operate with minimal return on investment.

An average stripper well produces 2.5 barrels of oil per day. At $25 per barrel and producing 25 days, this would gross $1,562.50. After taking royalty owners and overrides out—using an average

82 percent net lease—this leaves $1,281.25 for the working interest. Fixed costs—pumper, overhead, electricity, and ad valorem taxes—will average a minimum of $500. This leaves $781.25 monthly if there are no repairs or problems. And with old stripper wells there are usually plenty of problems. Conversely, if $100,000 were invested in a 10-percent interest-bearing account, investors could realize an earnings of $833.34 a month on the $100,000 investment. And this return on investment is guaranteed, unlike investing in an oil or gas venture.

Additionally, stripper wells are important to the United States All together, they produce a lot of oil: 426,502,365 barrels in 1981, or 13 percent of the total production in the United States.

Stripper wells account for 73 percent of the wells in the United States with an estimated recoverable reserves of 4.4 billion barrels. However, an average of 7,775 stripper wells are being abandoned each year. Any incentive to help keep these wells producing will help our country toward energy independence.

The future of the independent oilman is precarious right now. It changes daily with the happenings in the Halls of Congress, State legislatures throughout the country, and in decisions made by foreign countries concerning production and price levels.

Like many other industries, the domestic oil and gas industry is in a depression. The price of oil had declined 9 percent since January; we have little market for natural gas if we are even lucky enough to find some; bankruptcies are becoming common; the drilling rig count is down 47 percent compared to last year; the list goes on and on.

I come before you to point out our position as independent oil producers, to tell you that these tax incentives are working, and to ask that you not impose any new taxes nor take away any incentives that the independent oilman now has.

The oil industry is one of the base industries of the Nation's economy. Many wheels in this Nation would not turn without oil and gas. Our national security is jeopardized by the lack of sufficient reserves of hydrocarbons. We have come a long way in the last 2 years in becoming energy self-sufficient. Let's not damage the progress we have made.

In closing, I would like to highlight three key points:

No. 1, small independent oilmen must generate capital from outside investors; and

No. 2, without the existing tax incentives, investors simply will not invest in such high-risk ventures.

No. 3, independent oilmen collectively account for the lion's share of exploration in the United States.

Thank you. I would be pleased to try to answer any questions you may have for me at this time.

Mr. PICKLE. We thank you, Mr. Purdum, for a very good statement.

We are now pleased to hear from Mr. Thomas Cambridge, representing the Panhandle Producers and Royalty Owners Association. I understand you are from Amarillo? Will you proceed?

## STATEMENT OF THOMAS R. CAMBRIDGE, PRESIDENT, PANHANDLE PRODUCERS & ROYALTY OWNERS ASSOCIATION

Mr. CAMBRIDGE. I am a partner in Cambridge and Nail Petroleum Exploration Services, a small independent oil and gas exploration and production business located in Amarillo, Tex. I am here today in my capacity as president of the Panhandle Producers and Royalty Owners Association. PPROA is a regional oil and gas association which represents 625 producers and royalty owners who explore for and produce oil and gas in the Texas Panhandle and surrounding area.

We appreciate the opportunity to be heard today on the topic of tax treatment of producers of oil and gas.

The Texas Panhandle is an area of the country having an economy which is very sensitive to the oil and gas industry and consequently to the tax policy affecting oil and gas producers and royalty owners. Oil and gas was first discovered in the panhandle in 1918 and development has continued to the present. Both oil and gas have been developed and producing depths range from 2,500 feet to 25,000 feet.

Our area has developed into one of the major gas supply sources for the United States with the Texas Panhandle having a capability of supplying 5 to 10 percent of the Nation's natural gas needs.

Throughout the long history of oil and gas development in the panhandle, the independent operator has played a dominant role in the entire spectrum of petroleum activities, ranging from exploration drilling in the frontier areas to nursing the last economic drop of oil and last molecule of gas from stripper properties.

Typical of the rest of the country, our independent operators have tended to recycle their petrodollars back into new activities which will provide more energy. The risks inherent in the energy search have always been weighed against economic return and economic return to the investor must be balanced against tax consequences, as in any investment.

The independent in our area has traditionally had his profit center at the wellhead sales point and had little opportunity to have any downstream profits in transportation, refining or retail sales such as major oil companies do.

The topics of discussion here today then are a very integral part of our decisionmaking process involved in the risky business of investing in oil and gas exploration and development.

As independents like myself drill 80 percent of the exploratory wells each year, we stand to play a major role in whether this country shall continue to become less reliant on foreign oil. I can assure you that we take seriously our obligation to the public in the form of continued domestic energy production.

We feel that Congress, in the past, has recognized the risks inherent in oil and gas exploration and production and has provided the tax incentives necessary to raise the capital for these ventures. In recent years, though, we have seen an erosion of those incentives and each time a negative change is made, it becomes more difficult to raise the capital for new investments.

In my short career as an independent, I have seen the rate of percentage depletion cut from 27.5 percent to 16 percent with another cut scheduled for next year. I have also witnessed a new minimum tax on intangible drilling costs and, of course, the so-called windfall profit tax has been imposed. These acts have each reduced the incentives to explore, while the risks remain high.

As I stated at the outset, I am a small operator. My company operates as a partnership. We drill 15 to 20 wells per year with a cost range of $250,000 per well up to $3,500,000 per well. Through the partnership and consequently individually as taxpayers, my partner and I participate for an interest in each well and raise the money for the balance.

I recently asked my tax advisor to compute what percentage of each dollar of net revenue from oil and gas production that I have reinvested in exploration and production over the last 4 years. He came up with an average of 84 percent and a 1982 number of 102 percent.

I then asked him how much less cash would have been available for investment if it had not have been for tax deductions attributable to percentage depletion and intangible drilling costs. He came up with a 4-year average of 29 percent and a 1982 number of 31 percent.

If these numbers are applicable on a national basis, then we would say that without percentage depletion and without expensing of IDC's, independents would probably drill 30 percent fewer wells and we would lose the battle over oil imports. Conversely, if the depletion allowance were restated at the 1981 level of 22 percent and if the 20-percent minimum tax on IDC's were abolished, we would see an increase in funds available to drill wells.

I suggest that expensing of IDC's and percentage depletion are positive tax policy items which encourage capital formation for oil and gas exploration and promote energy development.

The Crude Oil Windfall Profit Tax Act of 1980 imposed an excise tax on each barrel of domestically produced oil. The preferential treatment of this act went to the major company and OPEC producers of foreign oil who were not subject to this tax.

Certain conditions and amendments to this act have since recognized that exemptions to independent domestic producers and royalty owners, in the form of lower rates on old oil and stripper oil, would return more revenue to those who create more domestic drilling activity and thereby increase the volume of oil discovered and produced in the United States. These exemptions are working to that end and should be kept in place.

Small royalty owners were especially hurt by the windfall profit tax and Congress has since amended the act to provide for minimal exemptions from the tax. These royalties are sometimes the sole source of livelihood for some citizens and taxing them is neither good tax or energy policy.

Mr. Chairman, it seems evident to the small independents and royalty owners, who I represent here today, that the deliberations of this committee will have much to do with the energy policy and consequently the energy self-sufficiency of this country, as well as tax policy. We urge this committee to consider the role that independent producers will play in the future and make your recommendations accordingly.

Thank you for this opportunity to be heard.

Mr. DORGAN [presiding]. Thank you very much for your statement. I would like to ask a general question and have any of you answer. It takes us in a little different direction.

The tax consequences you face as independent oil men are not only the Federal tax consequences but also State tax consequences. There are a lot of allegations made State to State these days about whether the tax level of this State or that State discourages or encourages activity by both independents and majors.

In my State of North Dakota, we have experienced a very precipitous decline in new drilling activity, just as it has occurred all around the rest of the country.

Some make the case that the State severance tax, or the State extraction taxes, play a major role in the decisions of where to produce.

By way of explanation, let me point out Montana, which is part of the same field, exploration field as exists on the western side of North Dakota, has had an extraction tax, combined, of somewhere close to 13 percent. North Dakota had an extraction tax of 5 percent. North Dakota increased its extraction tax from 5 to 11.5 total; so they were still slightly below the extraction tax of Montana.

There are some who suggest that the increase in the State severance tax or extraction tax has at least in part caused a precipitous drop in drilling activity. Any thoughts about how the States' tax rate on the activities of an independent oilman affects drilling decisions, exploration decisions?

Mr. CAMBRIDGE. I think it definitely does take from the cash flow available. For instance, in Texas we have a 4.6-percent severance tax on oil and 7.5 percent on gas. This raises—this tax raises $2.4 billion for the Texas treasury, which is 28 percent of the entire taxes collected by the State.

But it is in line with other States, and so I don't know that it has an impact in shifting whether a person would drill or not. It does account for a lot of tax elections in Texas.

Mr. DORGAN. Anyone else have thoughts?

Mr. STEWART. Oklahoma has a little over 7-percent tax on both oil and gas, on growth. It has been in place for a number of years. I don't think it has had any effect at all.

Mr. STAHL. I feel it has very little effect as between one State and another, whether you would make an election to drill in one State versus another, as long as they stay relatively consistent between States, and there is not a disparity between States. I don't think it has any influence whatsoever.

It does have an influence on how long you keep a well in operation. Obviously, you can also tax it out of existence, whether severance tax or whatever.

Mr. CAMBRIDGE. May I make a further comment on real property taxes in Texas? Again, we have oil and gas reserves that are taxed in the local counties, school districts, hospital districts, and such. Again, last year the collections on oil and gas accounted for, I think, 24 percent of all property tax collections in the State.

I know that in some districts that I operate in, the tax on oil and gas interest both to royalty owners and producers accounts for as much as 85 percent of the budget for schools and counties and hospitals.

We think that is a little out of balance. I think the point that you brought up does suggest that counteracting some of the comments we heard earlier about the fact oil and gas producers don't pay any tax. We do pay at the local, State, and Federal level.

Mr. DORGAN. The point that I hear in testimony is that to the extent that someone pursues a worthwhile activity or an important activity, one we need in this country, and to the extent that that person pays any kind of taxes and, therefore, taxes that otherwise could be used for pursuing that worthwhile activity, then we are not pursuing the goals that we would want as a country; namely, with respect to the production—or exploration of and production of oil.

I understand that. You are saying to the extent there is any tax, it is a disincentive if someone, instead of paying a tax, uses that as capital formation to go drill the wells.

The other side of that point is that in order to function as a country, everybody has to pay some taxes. We are a free country. We have a $250 billion military budget. That benefits the independent oil producers, the barber, the punch press operator in the factory. We all contribute to that. The fact is, we all have to pay some income taxes.

The question is: How do we pay them? Using what mechanism, do we pay income taxes? That is what we are trying to figure out here. The tax system, as it relates to the oil industry, is enormously complex. It almost has become a Lawyer and Accountant Relief Act because it employs so many people shuffling paper trying to figure out what the final tax consequence is for your industry.

Let me ask you a question that Mr. McIntyre asserted in his paper. I believe, Mr. Stahl, you cited Mr. McIntyre's testimony. Let me just also say I went back to look at his testimony relative to your question of it, and I think he was making a slightly different point than you were suggesting.

You suggested he was saying that independents spend $2 to find 1 dollar's worth of oil. They couldn't do that very long if that were the case. You are accurate about that. If independents are spending $2 to find 1 dollar's worth of oil, they wouldn't be independent oil people very long. They would be doing something else for a living.

His point in his testimony was that an economist named Harbin Gear once calculated that you have to spend $1.25 to make 1 dollar's worth of oil. What he was saying is through the profit statement, you pick up money. He was pointing out the tax break in addition to the other economic factors for drilling at least with respect to this one study—and I have no idea who the economist Harbin Gear is—but I think that is what he was citing.

I would like to read the other statement to you Mr. McIntyre made and ask your analysis of it. He says:

> For example, without expensing of intangible drilling costs, the IDCs, the risky exploratory drilling would be encouraged since dry holes would be entitled to a writeoff in any case. By extending the same treatment to successful wells, they discourage exploratory drilling in favor of punching new holes in old fields.

I think that is an interesting point. I would like to hear your response to it. I think I can anticipate it.

Mr. STAHL. It is an interesting point. It is a fallacious point in my judgment. It shows the money that is invested comes from no place; it is suddenly made up, put in. Every dollar that is invested comes as a source of income because it can come from no place else. Talking about the independent segment now of the oil industry.

Whether we raise that money from an individual or we generate it internally with our own funds, it has to be earned by somebody first before it can be invested in the oil business. If it has been earned by somebody first, then all that the tax benefits do is a shift of a portion of the burden of drilling from 100 percent on the investor to a portion of it to the Federal Government in the form of deductions; whether those are IDC's on producing wells or 100-percent writeoffs on drill holes is immaterial. It is a shifting of risk in the final analysis.

But every dollar that is invested by an independent starts out as an earned dollar by somebody. If it is an investor who is a doctor or a lawyer or a businessman or an elected politician who elects to invest with me, he has had to earn a dollar from some other source of activity. So, it is, therefore, an earned dollar that he then puts at risk with me.

If per chance that dollar turns out to be nonproductive and it is a dry hole, the economic impact is to shift a portion of that loss to the Federal Government. That is a policy decision which has been determined to be beneficial, because it encourages exploration.

Absent that policy, we simply would have one of two results: We would have less wells drilled or we would have the price of oil and gas skyrocket.

Mr. DORGAN. Do you know what makes people furious on the main streets of small towns in my State about our tax policy? They read a newspaper article that says according to SEC records Occidental Petroleum earned *x* amount of dollars, paid no income taxes. It makes them furious because they feel there is something dramatically wrong with the tax system.

In those instances, do you as a citizen believe there is something dramatically wrong with the tax system? Should we expect the majors, the integrated companies, if they are profitable to pay some reasonable amount of income tax?

Mr. STAHL. Are you asking me the question?

Mr. DORGAN. Whoever wants to answer.

Mr. STAHL. I feel the duty of Congress is to balance, to try to come up with a balanced policy that protects not only the free enterprise system, but protects also the citizens. That is the function of Congress. It is not the function of a businessman, like myself.

Once that has been established, inherent in that is the establishment of certain tax policies. Once those tax policies have been established, then I feel it is a duty of the citizen to maximize taking advantage—if you would—of legally taking advantage of the policies that have been established; and if the policy of Congress is to encourage oil exploration, and if there are tax advantages in doing so, then I think everyone should avail themselves of those opportunities because that is an expression of public policy.

If the people don't like the public policy, what they ought to do is change the politicians who in turn change the public policy.

Mr. DORGAN. My point is that you develop a credibility problem if you have examples of major economic enterprises that earn a substantial amount of money and pay no taxes. That seems to me and also the people on Main Street of the country who do pay taxes to be a failure of the tax system. I think the point you make is that to the extent the people feel that way, we change the tax system, in concert with other objectives, goals we might have as Americans: encouraging production, this, that.

Generally speaking, I think we are seeing some very dangerous storm clouds over our tax system in this country. We have a volunteer tax system. We can't prosecute 2 million people if they decide next year not to pay it. We don't have the capability to do that. We have a volunteer tax system.

To the extent the people feel that is fair and reasonable, they will cooperate with it. To the extent they feel it has eroded to the point of being almost dishonest, they, I think, will provide real difficulty.

That is why it is important for the Ways and Means Committee to try to steer a course that does what we want to do in terms of public policy objectives and at the same time creates a system the people in this country feel represents a fair and balanced approach to taking money from people and enterprises to pay for the things we have to do as a Government.

It is a very difficult thing for the Ways and Means Committee or Congress to try to interpret. We certainly have to regain the confidence of the American people in this tax system. That is why I asked the general question.

Mr. STEWART. I would like to make a comment on the depletion allowance. It was brought out two or three times. I think it would be well for the committee to absolutely understand this. It goes to the point of how you direct investment.

Right now I think there are some 28 minerals that have a 23-percent depletion allowance; uranium being one, perhaps gypsum; there are some other things. By that, the Congress is telling the people that we think it is in our national policy to give a greater tax benefit to uranium than to oil and gas.

I don't think that that is really what the Congress means to say. If we go down to the 15 percent, there will be 40 minerals out of something like 100 that will have a higher depletion allowance. Sand, gravel, all these others are involved.

Mr. DORGAN. Doing something new is significantly different than changing something that has been done with respect to the actions of Congress. I think you make an interesting point.

Mr. STAHL. Congressman, you made one point that I agree with when you said that you have to structure a tax policy that the American people have faith in. Otherwise they are going to cheat. Keep in mind that with respect to the oil business, that every time you take a dollar away from us in taxes, basically you are taking that same dollar and the American people are spending that for a barrel of oil from Saudi Arabia. A certain level of crude has to come into this country, whether it is domestically produced or foreign produced.

As long as we are importing a substantial number of barrels, then it is a question when you shift dollars and say take it from the oil industry; true, you are taking it from the oil industry; you are putting it into the coffers of the Federal Government, and it is being spent for whatever programs—defense, social policy, whatever—the Federal Government spends it for.

By the same token, that barrel of oil has to be made up by the American public. That is, it has to be bought from a foreign source. That, in our judgment, is not good public policy.

Mr. **Dorgan**. I understand your point. It is an important point. The question that has been raised frequently is the efficiency of the tax—with the foregone revenue in the form of a tax break. What is the efficiency of it? If we spend $1 billion on a special tax provision in order to encourage something, what have we purchased with that? What has been the result of encouraging that?

I think what we need to do is look at the efficiency of the various provisions of the law that forego revenue that would otherwise—in order that the Federal Government simply, as a normal course of receiving revenue under the income tax system.

I understand your point. Let me say we appreciate having a panel like this testify before the committee. I have said before that there is no agenda here that suggests any significant changes or suggests we won't make changes. We are simply trying to establish a record of what exists and what the experience has been with the current tax law.

Your contributions have been very significant. We will include your full statements as part of the record. We appreciate very much your willingness to come and testify today. Thank you.

We would like to combine the next two panels. If the second panel is here, we have in the first panel two persons, the Illinois Oil & Gas Association represented by C. L. Glover, Jr., president, accompanied by Lelan Russell, executive assistant; and the Ohio Oil & Gas Association represented by J. C. Morgan, president; and I would like to ask if Mr. Robert Soaper is here, and Mr. Wayne Harmon?

Please come to the witness table, as well, the Kentucky Oil and Gas Association, Robert Soaper, president and the Louisiana Association of Independent Producers and Royalty Owners, Wayne Harmon, executive vice president.

## STATEMENT OF C. L. GLOVER, JR., PRESIDENT, ILLINOIS OIL & GAS ASSOCIATION, ACCOMPANIED BY LELAN RUSSELL, EXECUTIVE ASSISTANT

Mr. **Glover**. I represent not only myself but our association, which is composed of basically independent oil producers, producing from wells that average less than 3 barrels a day. You can see from some of the statistics I presented on the first page that we are not impressive until we get to the real numbers of the facts that Illinois crude oil purchasing companies mail out 160,000 checks every month to Illinois residents. These checks are vital to counties such as mine that had a 27-percent unemployment rate in February.

I would like to point out, as many others have, that if we as independents don't keep adding to our inventory or what we term as reserves, we will produce ourselves out of business. The way we ordinarily add to our reserves is through drilling. We can only do this by virtue of risk capital.

I have included a graph marked "exhibit A" and entitled "Number of New Holes Drilled" showing some peak periods from 1940 and 1945, 1954 through 1956, and 1981 and 1982. The depressions are particularly interesting. They reflect the fact when we have had negative impact from the Government, that drilling in Illinois has dramatically declined.

In addition to the—well, in particular, I want to point out "D" and the "D" section was placing of the wellhead price controls on natural gas by the Supreme Court in the *Phillips* decision which caused this 16-year price deterioration in crude oil.

The second influence on this 16-year decline was the importing of cheap foreign crude. For major oil companies it was simple economics. It was less expensive to develop and produce imported crude oil than develop the same reserves domestically.

Independents in Illinois couldn't compete with this. Our numbers dwindled from 1,000 in 1956, to 400 by 1970. This illustrates a difference between majors and independents. The majors operate on a global scale, moving their resources and equipment and product into and out of large theaters of operation such as the North Sea and the Persian Gulf.

In comparison, as an independent, I operate in six counties in Illinois and sell my product to major oil companies. You can go ahead through that graph and see where drilling declined in "E" from when we lowered the depletion allowance from 27.5 to 22 percent; "F" was the price controls; "G," the Arab embargo where oil prices were rising only by Government edict; and down through the end of the graph.

These ups and downs clearly show the influence of Government on drilling activity in Illinois. One of the fellows on the previous panel was one of the first people that I heard discuss anything about an independent purchasing producing properties from major oil companies or other independents. We can add to our inventory in this way.

I purchased wells from Union Oil Co. in California that were producing such a small amount Union could no longer afford to operate. My cheaper operating cost and lower overhead will extend the life of a marginal stripper well for years.

I have also listed an example here of five wells I own in Madison County that are 100 miles from my other operations. By virtue of this, I have to contract the servicing of the wells because of the distances involved. At some point, these properties will become uneconomical to me and I will either sell them or plug them. An operator in that area can service the wells himself and lower the operating cost and extend the life of the property.

The purchaser of a marginal stripper property is very much at risk. The down-home conditions are unknown and Government regulation is in a constant state of flux. He doesn't have the percentage depletion. Stripper production could be exempt from the proven interest rule. It can mean the difference between plugging and producing.

Producing means the conservation of valuable natural resource, jobs, and the retention of a tax base. Questioning someone earlier about paying taxes in counties and State level, in the nine most productive counties in Illinois, oil provides from 20 to 25 percent of the entire county tax base.

We heard a lot of generalities about wells. I would like to use Keller Community No. 1 as an example of the marginality of some of these wells. In 1982, I had operating expenses of $1,018.19, depreciation of $450, paid windfall profits tax of $149.19; had administrative expense of $183.57 for a total expense of $1,800.95. My oil sales totaled $2,204.08, realizing a net gain of $403.13. Any additional taxation will kill this Keller Community No. 1.

Only a small independent can show a profit operating a well such as this. My father and I also operate a shallow Pennsylvania sand waterflood in Crawford County. Out of 22 leases in the flood, 10 operated at a loss in 1982. We continue to operate these leases anticipating, in the not too distant future, price technology and domestic energy policy will permit a tertiary recovery project.

If we abandon these wells, the chances of placing a tertiary oil recovery project is virtually lost. What we have to have is stability from the Federal Government and not a new tax law every year.

The second graph I presented illustrates the fact when we have increased drilling, we are going to have increased production. The graph also illustrates the value of maintaining stripper production until technology can be found to get more oil out of the ground.

The white part of the bars from roughly 1950 on is a result of secondary recovery operations. If we can maintain the 95 percent of Illinois wells which are now stripper production until such time as tertiary or enhanced oil recovery achieves economic breakthrough, we can produce a great deal more oil from Illinois' known reservoirs.

In addition, in Illinois, we have, to the 1.5 billion barrels the State survey estimates we have left to be found in nonproducing horizons, we have 45,000 cubic miles of Cambro-Ordovician lying under the State that have productive potential.

It would be an expensive venture for us, costing somewhere around $400,000 just for the drilling and a completed test would cost $1.5 million which is about 10 times the cost of 1 of our 3,000-foot McClosky wells. Again, we must have risk capital for this kind of drilling.

My hometown of Olney, Ill., is in Richland County. Our local economy rests on a triple base. A manufacturing plant that produces tricycles and bicycles, our agricultural community has just received a $5,700,000 boost from the Federal PIK program. Roadmaster, our bicycle manufacturer, just received a $2,550,000 urban development action grant for retooling.

Only the oil industry is not feeding at the public trough. Independent oil producers are an endangered species existing in the United States, Canada, and Australia. Our existence will be assured as long as we are not regulated to death and are able to attract outside risk capital.

In a nutshell, tax advantages for investors equal risk capital, risk capital equals production and jobs. As an Illinois independent, I am not asking nor are we as a group—nor have we as a group ever asked to be treated in a way that would be detrimental to others. We are not asking for a PIK program or urban development grant.

We are asking you give to us the opportunity to strive for the maximum limit of domestic crude oil production.

If you have questions at a later date or would like to buy a 32d interest in a working well, see me.

[The prepared statement follows:]

### STATEMENT OF THE ILLINOIS OIL & GAS ASSOCIATION AND ITS PRESIDENT C. L. GLOVER, JR.

Mr. Chairman and members of the Sub-Committee, I am C. L. Glover, Jr., an independent producer from Olney, Illinois and current President of the Illinois Oil & Gas Association, whose headquarters is located in Mt. Vernon, Illinois.

I will limit my remarks to independent oil producers represented by our Association and personal observations about my immediate sphere of operations.

The Illinois Oil & Gas Association is composed of 2,500 individual members over 600 companies employing 8,000 people. These 600 companies are directly involved in the exploration for and the production of crude oil and natural gas; some as producers, some provide supplies and some are service oriented. Over 400 of these companies are small independent producers and of that number approximately 150 produce less than 1,000 barrels of oil per day from wells that produce on average less than three barrels of oil per day. However, the effects of our industry run much deeper than these figures would lead you to believe. Crude oil purchasing companies mail out to Illinois residents an average of 160,000 checks per month to royalty owners, investors, farmers and operators. These checks are vital to counties such as mine which had a February unemployment rate of 27%.

Every barrel of oil produced by an independent comes from inventory; and in order to grow or even to keep from producing ourselves out of business, we must add to inventory. We can do this by drilling, and the most important prerequsite for drilling is the ability to attract outside risk capital in the hope of high returns and some attractive tax situations, such as those under discussion by this Committee. Please note this as an important difference between independents and majors.

In Illinois there is a direct relationship between the number of holes drilled and the economic and regulatory-tax climate. This relationship is shown on the graph marked Exhibit "A" and entitled "Number of New Holes Drilled." There are three peak periods shown on the graph. These are 1940 and 1941, 1954 through 1956 and 1981 and 1982. These are periods when oil companies could prosper through drilling in Southern Illinois. The depressions on this graph are explained as follows.

"A" World War II with its scarcity and control of tubular goods and other oilfield iron.

"B" Represents the end of World War II but still under PAD control which ended at "C".

"D" Was the placing of wellhead price controls on natural gas by the Supreme Court decision in the *Phillips* Case. This actually occurred in late 1954 but its effect took several years to filter through the economy and was not felt until 1957. This caused 16 years of oil price deterioration. A second influence on this 16-year decline was the importing of cheap foreign crude oil. For major oil companies it was simple economics. It was less expensive to develop, produce, and import crude oil than to develop the same reserves domestically. Independents in Illinois could not compete with this cheap crude. We dropped into recession and saw other companies dwindle from 1,000 in 1956 to only 400 in 1970. This illustrates another difference between independent and major companies. Major companies operate on a global scale moving their resources, equipment and products into and out of large theatres of operation; such as the North Sea and the Persian Gulf.

In comparison, I operate in six counties in Illinois and sell my product to major oil companies.

In retrospect, perhaps we as a Nation, should have given more assistance to the domestic oil producer during this period so that when the price supply crunch came, its effects would not have been so dramatic. You and I know that this current temporary oil glut in the international market has not eliminated our dependence on imports or future price escalations.

"E" Was the drop in the depletion allowance from 27½ to 22 percent.

"F" Was the 1970 price controls which were lifted in 1972 on everything except oil and gas.

"G" Was the Arab Oil Embargo. Prices were then rising on oil and gas by government edict.

The drop in drilling at "H" in 1976, was due to the placing of 15% of our tangible drilling cost in the minimum tax category.

"I" Was the release of price controls on crude oil by the Federal Government. These ups and downs clearly show the influence of government on drilling activity in Illinois.

As an independent I can also add to my inventory by purchasing producing properties from major companies or other independents. Ordinarily, a property is placed for sale because its owner is operating it at a loss. I have purchased wells from Union Oil Co. of California that were producing such a small amount of oil that Union could no longer afford to operate the property, but my cheaper operating cost and lower overhead will extend the life of a marginal stripper well for years. As another example, I own five wells in Madison County, Illinois. These wells are a hundred miles from my other operations. Gross production from the five is currently ten barrels per day. Because of the distance involved, I contract the operation of the wells. When the properties become uneconomical to me, I'll either plug them or sell them. An operator in that area, who can service the wells himself, may lower the operating cost and extend the life of the property. The purchaser of a marginal stripper is very much "at risk." The down hole conditions are unknown, Government regulation is in a constant state of flux and he does not have percentage depletion. Maximum tax advantages should be retained in these sales. Stripper production should be exempt from the proven interest rule. It can mean the difference between plugging; and, producing means the conservation of a valuable natural resource, jobs, and the retention of tax base. In fact, in the nine most productive counties in Illinois, oil provides from 20 to 25 percent of the entire county tax base. Additionally, each operating well is a little plus for our balance of payments because its that much more we don't have to import.

I would like to use my Keller Community No. 1 as an example of the marginality of some wells. In 1982, I had operating expenses of $1,018.19; depreciation of $450.00, paid Windfall Profit Tax of $149.19, had administrative expenses of $183.57, for a total expense of $1,800.95. My oil sales for 1982 totaled $2,204.08, realizing me a net gain of $403.13. Any additional confiscatory taxation will kill the Keller Community No. 1. Only a small independent can show a profit operating a well such at this. No major can do it, no public utility, no government bureaucracy.

My father and I operate a shallow Pennsylvanian sand waterflood in Crawford County, Illinois. Out of the 22 leases in the flood, ten operated at a loss in 1982. We continue to operate these ten leases anticipating that in the not too distant future—price, technology and domestic energy policy will permit placement of a tertiary recovery project. If we give up, abandon, and plug the aforementioned ten leases the chance of placing a tertiary oil recovery project is virtually lost. What we need from you is stability and not a new tax law every year.

The second graph, marked as Exhibit "B" and entitled "Crude Oil Production" is presented to show that production can be increased when economic conditions permit sufficient drilling. There is, of course, a lagtime between drilling and increased production. It also illustrates the value of maintaining stripper production until technology can be found to get more oil out of the ground. The white part of the bars from roughly 1950 on is the result of secondary recovery operations. If we can maintain the 95 percent of Illinois wells which are now stripper production until such time as tertiary or enhanced oil recovery achieves an economic breakthrough, we can produce a great deal more oil from Illinois known reservoirs. Not only do we have tertiary projects to look forward to in Illinois, we have an estimated one and one-half billion barrels to be discovered in known producing horizons. In addition, there are 45,000 Cubic miles of Cambro-Ordovician age sediments lying under the State of Illinois that have productive potential. This geological section produces in Western Tennessee, Kentucky, Northeastern Indiana, Northwestern Ohio and to the Southwest in Oklahoma and Texas in what is known as the Knox formations. Only a dozen wells have been drilled to the Knox in Illinois. The drilling of a Knox test in Illinois will require an expenditure of over $400,000, just for drilling. A completed Knox test, will cost one and one-half million—ten times the cost of a 3,000 foot McClosky well. Again, risk capital is a must for drilling.

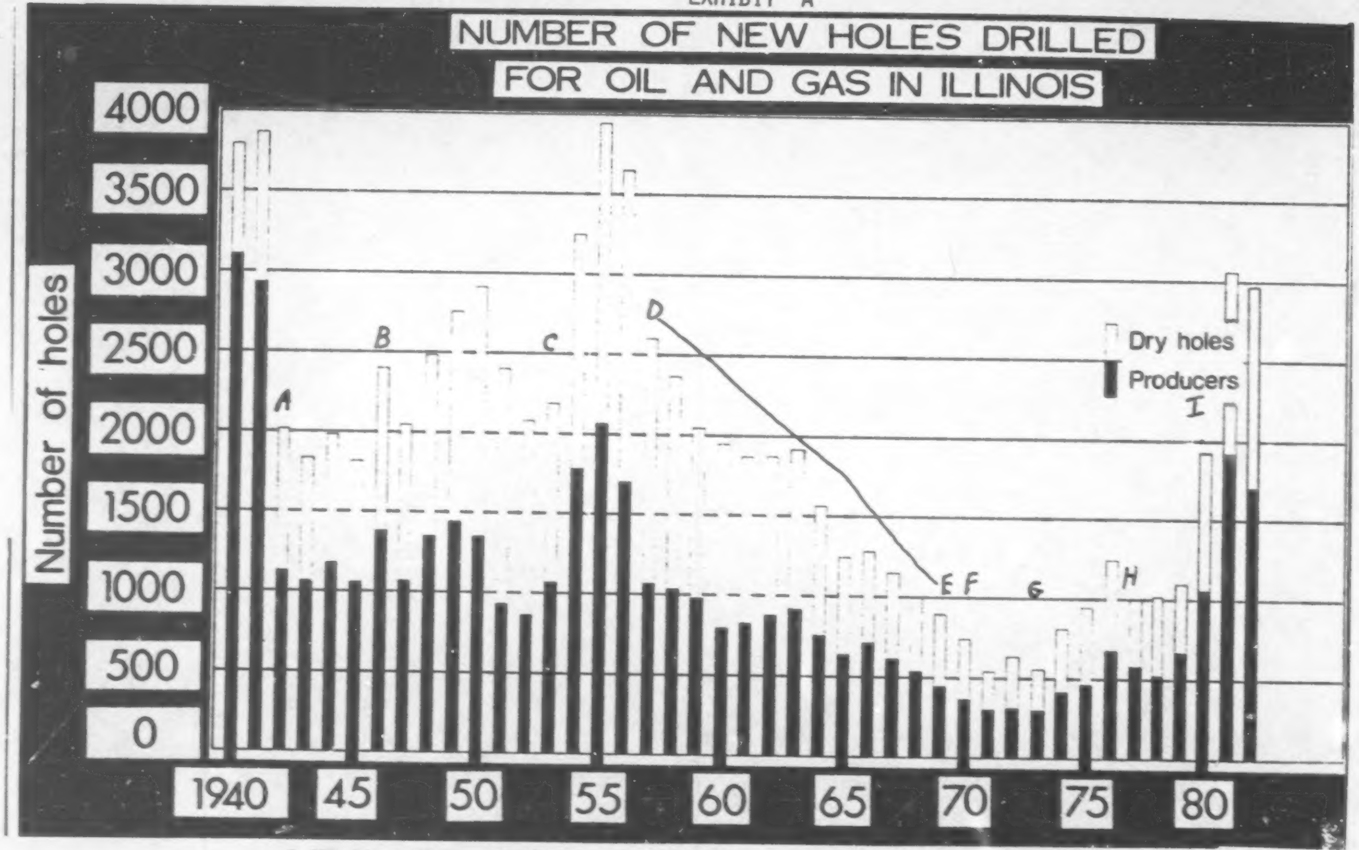
My hometown of Olney is in Richland County and our local economy rests on a triple base. A manufacturing plant that produces tricycles and bicycles; agriculture, as well as the oil industry—primarily composed of independents operating stripper wells. Our agricultural community has just received a $5,700,000.00 boost from the Federal P.I.K. program. Roadmaster, our bicycle manufacturer just received a $2,550,000 Urban Development Action Grant for retooling. Only the oil industry is not feeding at the public through.

Independent oil producers are an endangered species, existing in the United States, Canada and Australia. Our existence in the United States will be assured as long as we are not regulated to death, and are able to attract outside risk capital. In a nut shell—tax advantages for investors equals risk capital and risk capital equals production and jobs. As an Illinois independent, I am not asking, nor have we as a group, ever asked to be treated in a way that would be detrimental to others. We're not asking for a P.I.K. program nor an Urban Development grant. * * * we are asking that you give us the opportunity to strive for the maximum limit of domestic crude oil production.

If you have any questions at a later date * * * or, would like to buy a thirty-second interest in a well, I have included my address and phone number.

Thank you very much.

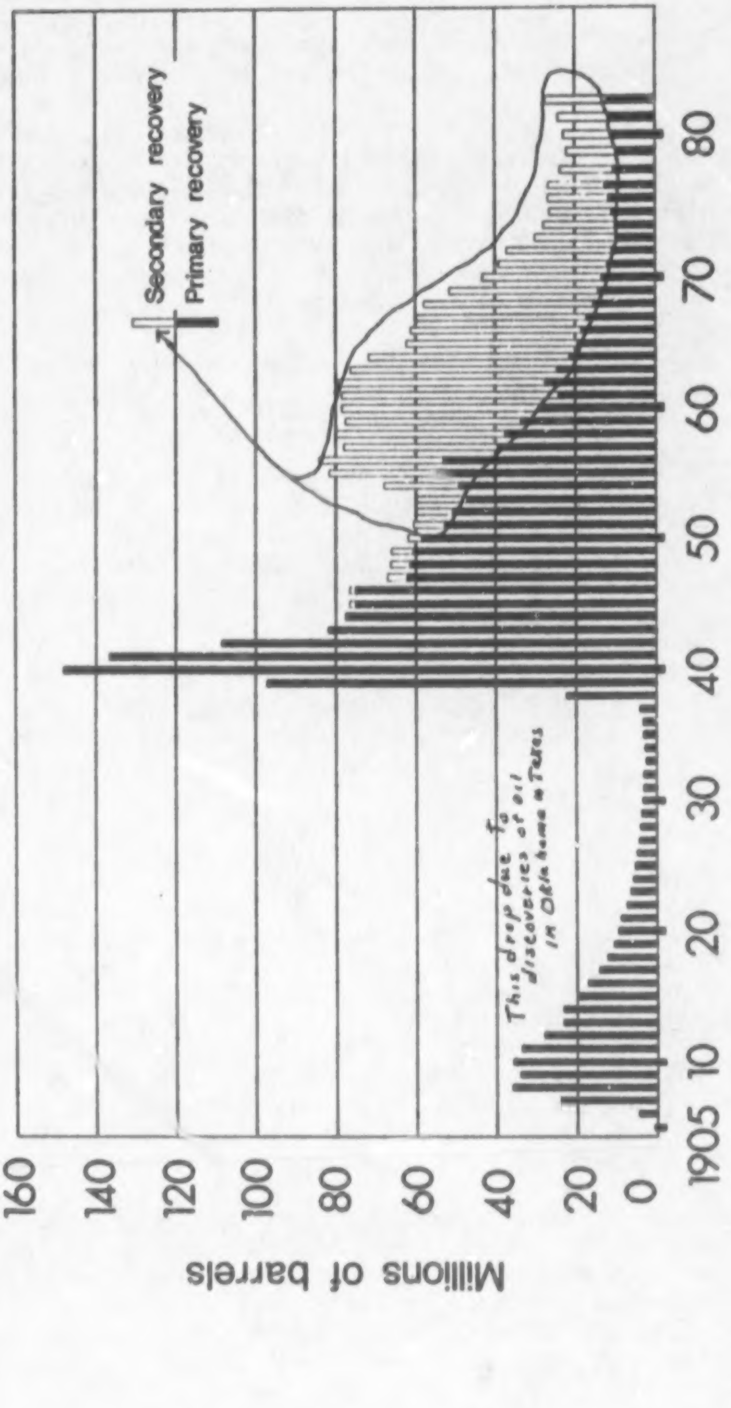
EXHIBIT "A"



A WW II & PAD
B End WW II
C End PAD
D Effect of "Phillips Case
E Depletion drop
F Govt. Price Controls
G Arab Oil Embargo
H Effect of IDC change
I End Govt. Price Controls

EXHIBIT "B"

## ANNUAL CRUDE OIL PRODUCTION IN ILLINOIS



This drop due to discoveries of oil in Oklahoma & Texas

Mr. **Dorgan**. Let me just comment that on page 5, you made the statement "What we need from you is stability, not a new tax law every year." You are talking about something that is very important. Stability is important and predictability in tax law is important.

When Adam Smith was writing about the maximums of tax law a couple of hundred years ago, one of the maximums was that people be able to understand what the obligation is. We have not been good in providing a stable and protective revenue system so that people would understand what their obligation is and what it is over a period of time. You make a very interesting point.

Does Mr. Russell have a statement?

Mr. **Glover**. No.

Mr. **Dorgan**. We would like to hear from J. C. Morgan.

## STATEMENT OF J. C. MORGAN, PRESIDENT, OHIO OIL & GAS ASSOCIATION

Mr. **Morgan**. I am J. C. Morgan. I am from Wooster, Ohio, and I am appearing before you today as president of the Ohio Oil & Gas Association. I am a native Ohioan, the third generation in my family to be involved in this industry. I have been making my living as an independent oil and gas producer for nearly 24 years. I am a native Ohioan.

The Ohio Oil & Gas Association represents more than 3,000 small independent producers and members of allied occupations such as geologists, suppliers, contractors, landowners, and investors. Our members employ as many as 100 people and as few as three people. In total, more than 15,000 people are employed in the oil and gas industry in Ohio.

The industry is vitally important to Ohio's economy. The search for energy in Ohio in 1982 contributed more than $700 million to the State's economy while the value of the oil and gas produced in Ohio added an additional $700 million last year. We estimate that approximately 70 percent of the funds raised to finance drilling activity in Ohio come from investors outside the industry, while the remaining 30 percent is about evenly divided beteen in-house cash flow and from financial institutions.

Independent producers in Ohio have traditionally reinvested in their businesses more than 100 percent of the income derived from those businesses. Oil and gas drilling operations are found throughout the eastern third of our State from Lake Erie south to the Ohio River, although all but 20 of Ohio's 88 counties have some oil and gas production.

Service and supply companies are located throughout this area selling oilfield supplies, running electric logs, cementing and fracturing wells, and providing other similar services. The majority of wells in Ohio have been drilled by cable tool rigs and take from 30 to 45 days to complete. The balance of the wells have been drilled by rotary rigs which take from 5 to 10 days to complete.

The vast majority of Ohio wells are produced from a low porosity, low permeability sandstone called, locally, the Clinton sand. The current average depth of an Ohio well is 3,607 feet and 141,894 such wells have been drilled since production started in Ohio, with about 41,000 of this type well in production at the end of last year.

These wells produce more than 37,000 barrels of Penn grade oil daily and 140 billion cubic feet of natural gas per year.

It is interesting to note about 70 percent of the crude oil production is produced from stripper wells. All Ohio wells must be artificially stimulated to bring them into production. This is accomplished by a technique known as fracturing. Most would produce nothing without this stimulation process. Our typical well costs about $150,000 to drill and complete and will produce comparatively low volumes over an average period of 7 to 10 years, many producing at less than 10 barrels a day.

On the up side, the Clinton sand reservoir exists fairly uniformly in the eastern part of Ohio making it a relatively low-risk/low-yield area. Obviously, this sort of situation lends itself greatly to the small investor who wishes to involve himself in low-risk/low-yield small dollar investments. It is accurate to say that you will find no big hitters in Ohio oil and as production.

This production, while economically marginal, is of great importance to the economy of Ohio and the overall effort of developing America's domestic reserves in a prudent and timely manner. It is well to note here that Ohio produces 65 percent of all Penn grade crude oil in the world. Penn grade crude is the best lube stock in the world and 35 percent of all lubricating oil marketed in the United States is refined from this particular grade of crude oil.

I hope this background helps you understand the role of the small producer in a State like Ohio. Almost 100 percent of Ohio's producers are true independents. They make their living from the production and sale of oil and gas from the wellhead.

Unlike the majors—the integrated oil and gas industry—we have no means of passing on our production costs through other operations such as refining or marketing. Unlike other industries, we seldom have the opportunity to set the price for our product. By and large, those prices are set by the purchasing companies with a little advice and guidance from Federal agencies and, yes, from the Members of Congress.

When you talk about tax law or changes in such laws as they relate to the oil and gas industry, I beseech you to be concerned about what these changes might do to the little guy, to the small independent producer. We are the people who pay the taxes you are discussing in this subcommittee. Even a slight change in the tax law has a major effect on the small independent producer.

While some changes you may be considering might not cause a ripple in the operation of a large company, it could be disastrous to the small producer and to the industry as a whole in Ohio. Any action that would detrimentally affect the tax treatment of our intangible drilling costs, percentage depletion, and the stripper well exemption from windfall profits tax could only lead to further decreases in the incentive to our investors in whom we are so vitally dependent.

If anything, our investors need more incentive, not less. Percentage depletion is an excellent example of a tax change that has increased our cost of production and we are still struggling to live with this policy. I implore this committee to consider that the current tax treatment for intangible drilling costs is a true incentive to invest in Ohio oil and gas wells. We ask that you not change the tax treatment for intangible drilling costs, for if you do it will destroy our market for venture capital and would be the beginning of the end for the oil and gas industry of Ohio.

Percentage depletion is an example of a tax change. Ohio producers are still struggling to live with this policy. With the knowledge that the vast majority of Ohio oil wells are stripper wells, you can appreciate the relief Ohio producers felt with the stripper well exemption from the windfall profit tax.

It is not difficult to reason there are no windfall profits associated with Ohio stripper wells that cost $150,000 to drill and complete. To reimpose a tax of this nature on this type of production could only have a negative effect on this small but yet very important resource.

We are small businessmen. We are proud of our industry and of our contribution to the well-being of our State. We need your help and understanding if we are to continue to be a viable part of our Nation's economy.

On behalf of the oil and gas industry in Ohio and myself, I thank you very much for your attention and for the opportunity to present our case to your committee. I will be glad to answer any questions the committee might have.

Mr. **Anthony**. Thank you, Mr. Dorgan.

The next witness represents Kentucky Oil & Gas Association, Mr. Robert C. Soaper, president.

## STATEMENT OF ROBERT C. SOAPER, PRESIDENT, KENTUCKY OIL & GAS ASSOCIATION

Mr. **Soaper**. My name is Robert Soaper. I am the president of the Kentucky Oil & Gas Association.

I appreciate the opportunity to present the views of the Kentucky crude oil and natural gas production industry regarding the treatment of different types of oil and gas producers.

In Kentucky, the crude oil production industry consists predominantly of independent producers rather than major integrated oil companies. Although a few large independent producing companies are active in Kentucky, the vast majority of Kentucky producers are small independents operating from a very limited financial base.

According to the most recent data on Kentucky crude oil production, there are approximately 16,000 active oil wells in the State producing an average of 1.1 barrels of oil per day. Although the current level of crude oil production in Kentucky is very modest in comparison to other States, there has been a dramatic upswing in drilling activity in the last several years that appears likely to result in significant increases in crude oil production levels in the near future.

Because of the relatively low productivity of oil wells currently operating in Kentucky, very few of the independents operating in Kentucky have the ability to finance the drilling of new exploratory wells using internally generated capital. Instead, a substantial portion of the new exploratory and developmental wells in Kentucky have been financed through limited partnership or other financial arrangements relying upon funds provided by outside investors. The availability of investment capital is directly affected by the treatment of such investments under our Federal and State tax law.

Favorable tax treatment of investments in independent oil and gas operations has clearly provided a major stimulus to oil and gas exploratory and developmental activities in Kentucky which appears likely to contribute to increased production levels in the near future. Because of the predominance of independent producers in the Kentucky crude oil industry and their reliance upon outside investment capital, congressional action on tax incentives for independent producers could affect the Kentucky crude oil industry to a far greater extent than the industry in most other States.

The upsurge in crude oil exploratory and developmental activity in the Kentucky oil fields over the past several years has been a godsend to those communities fortunate enough to have significant crude oil resources. In many instances, expenditures by drilling and producing companies have sustained the economy of local communities while the economy of neighboring areas without crude oil resources virtually collapsed. The benefits of increased drilling and production activity have been funneled into the local economy through service and supply industries ranging from hardware companies to the legal profession.

In human terms, crude oil production has sustained employment levels in those counties having crude oil resources while neighboring counties experienced record unemployment.

Increased crude oil production activity has also boosted State severance tax payments in Kentucky at a time of critical need because of the slumping coal industry. In 1982, crude oil production severance tax payments increased approximately 10 percent to over $10.3 million.

Although statewide crude oil production figures are not yet available for the first quarter of 1983, data is available for Henderson County, Kentucky's largest crude oil-producing county, which may be projected on a statewide basis. In the first quarter of 1983, Henderson County production levels were 30 percent higher than for the same period in 1982. These figures indicate that the crude oil production industry in Kentucky is likely to play an increasingly significant role in the State's economy.

Since the continued progress of the crude oil production industry in Kentucky is tied so closely to independent drillers and producers whose success is so dependent upon the tax treatment afforded their operations, on behalf of the Kentucky Oil and Gas Association, I urge you to be especially sensitive to the needs of independent crude oil producers.

Thank you.

Mr. ANTHONY. Thank you very much, Mr. Soaper.

I would bring it to your attention, a member of your congressional delegation, and a good friend of mine, Representative Carroll Hubbard, made a special request to this committee seeking permission for you to testify. With the Congress having adjourned early this week, many Members hopped on airplanes and headed home. Congressman Hubbard is probably hosting a large delegation, preparing for tomorrow's event. Unfortunately, I was unable to accept his invitation.

We have Mr. Wayne Harmon, representing the Louisiana Association of Independent Producer and Royalty Owners.

I welcome you before the committee. My district is the 4th District in Arkansas, so I share a common border all the way across the State of Louisiana with Mr. Roemer on one corner and Mr. Huckaby on the other corner.

### STATEMENT OF WAYNE HARMON, EXECUTIVE VICE PRESIDENT, LOUISIANA ASSOCIATION OF INDEPENDENT PRODUCERS & ROYALTY OWNERS

Mr. **Harmon**. I am a native of Texarkana.

I am the executive vice president of LAIPRO, which is an 1,800-member organization of independent producers and royalty owners with interests in the State of Louisiana. Most anything I would say right now would be redundant of what we have heard the last 2 days.

I would like to just briefly share some of the activities going on in the State of Louisiana and the effect of the independent oil and gas business in the State.

Over $1.5 billion in severance taxes and lease incomes paid by the oil and gas producers to the State of Louisiana forms the backbone of the State's financial situation. The State's income depends on a healthy state of our industry.

Not only has the production level of crude oil declined in the State, but recent decreases in oil prices have further aggravated the State's financial problems. Figures furnished by the Louisiana Legislative Fiscal Office show any downturn change in the price of crude oil has had a significant effect on Louisiana's financial situation.

For example, the recent decrease will, during the present fiscal year, July 1982 through June 30, 1983, affect revenues in the following ways:

One, crude oil severance tax, which is currently 12.5 percent of value collections, will be lost, $127 million. Royalty revenues lost to the State, $40 million. Sales taxes lost directly from the industry $40 million to $50 million. Corporate income taxes lost directly from the industry, $20 million to $30 million. This yields a loss to the State in the fiscal year 1982–83 of $227 to $247 million.

These figures do not take into consideration the many indirect effects such as personal income taxes, employment figures, and sales taxes by individuals employed by the industry.

It is a fact, however, that every $1 drop in the price of crude oil costs the State of Louisiana in excess of $31 million in severance taxes and royalties alone.

Our industry has demonstrated that we respond to economic incentives and disincentives. For instance, the State of Louisiana's oil production peaked in 1971 at just over 80 million barrels. By 1979, that production had declined to just over 400 million barrels, a loss of 50 million barrels per year during that period.

At that rate of decline, Louisiana would have been essentially out of the oil-producing business in another 8 years. With higher prices, however, allowed under the NGPA, and the decontrol of crude oil prices in 1980, we witnessed a great upsurge in domestic oil and gas drilling.

As a result of these incentives, Louisiana stabilized her crude oil production at 1978 rates for the last 4 years. This same thing is true for natural gas.

Not only does the slowdown affect the State, but this situation affects producers, drilling contractors, service companies, transport companies, tugs and barges, and all other support services. Many of our large drilling contractors currently have more than 50 percent and in some cases 75 percent and more of their rigs stacked with no jobs in sight.

In summary, among the States in the United States, Louisiana is a major petroleum producer. It is the third largest producer of crude oil, and the second largest producer of natural gas.

Second, over the 1955 to 1980 time period, employment in the oil and gas extraction sector grew faster, 115 percent, than employment in the total manufacturing sector of the State, 77 percent.

Third, Louisiana is the only State in the United States that every parish, and in any other State's calculation that is a county, has oil and gas production.

State government revenues in Louisiana is dominated by collections from the petroleum industry. Collections from taxes, royalties, rents and bonuses account for more than 50 percent of all undedicated funds collected by the State treasury.

Last, more than 95 percent of all the wildcat wells drilled in Louisiana are drilled by the independent oil and gas sector.

Mr. Chairman, the independent oil and gas sector is an important one indeed. However, due to extraordinary risk and dollar investments, it is absolutely imperative that the existing exemptions for independent producers, which is the subject of these 2 days of hearings, remain.

Thank you.

[The prepared statement follows:]

## STATEMENT OF WAYNE HARMON, EXECUTIVE VICE PRESIDENT, LOUISIANA ASSOCIATION OF INDEPENDENT PRODUCERS AND ROYALTY OWNERS

Thank you, Mr. Chairman. My name is Wayne Harmon. I am Executive Vice President of LAIPRO—the Louisiana Association of Independent Producers and Royalty Owners. LAIPRO is a state trade Association in Louisiana which represents more than 1,800 members and promotes the interests of independent oil and gas producers, royalty owners, landowners, geologists and others with operations in the State of Louisiana. LAIPRO is headquartered in Baton Rouge, Louisiana.

Mr. Chairman, LAIPRO completely endorses and associates itself with the comments made yesterday before this committee by the Independent Petroleum Association of America. We do, however, ask for the opportunity to file with the Committee a more technical supplement which will address the eight (8) specific items as it relates to independent producers in Louisiana. I would like to share with the Committee the situation the petroleum industry finds itself in today in the State of Louisiana, which has a direct relationship on the hearings being conducted by this committee.

It is not uncommon for a state's economy to be dominated and heavily dependent on one particular industry. In Louisiana one is aware of the profound and pervasive impact of the petroleum industry on the state's economy. Louisiana ranks a close second to Texas in the Nation in natural gas production and third (behind Texas and Alaska) in crude oil production. Louisiana provides more than one-third of the natural gas and about 15 percent of the crude oil produced in the United States. In fact, Louisiana produces an amazing 11.5 percent of world gas production, which is far out of proportion to the state's relative geographic size.

The point here is—the State of Louisiana's economy does depend on the oil and gas industry. The State of Louisiana has for many decades depended upon oil and gas revenues to finance programs and services. In the last fiscal year, oil and gas severance taxes paid totaled more than $971 million. This was roughly the equivalent to one out of every three tax dollars collected by the State Treasury. In addition, our industry paid more than $624 million in royalties, rentals and bonuses in connection with oil and gas produced on state lands and water bottoms.

This one and a half billion dollars in severance taxes and lease income forms the backbone of Louisiana's state finances just as direct employment of 165,000 workers in the oil and gas industry and the creation of tens of thousands of jobs in support roles form the backbone of Louisiana's economy.

Not only has the production level of crude oil declined in the State, but recent decreases in world oil prices have further aggravated the State's financial situation.

Figures furnished by the Louisiana Legislative Fiscal Office show any downward change in the price of crude oil has a significant effect on Louisiana's financial situation. For example, the recent decreases will, during the present fiscal year (July, 1982–June, 1983), affect revenues in the following calculable way:

(1) Crude oil severance tax, which is currently 12½ percent of value, collections lost: $127 million.

(2) Royalty revenues lost: $40 million.

(3) Sales Taxes lost directly from the industry: $40–50 million.

(4) Corporate income taxes lost directly from the industry: $20–30 million.

These figures yield a total calulable loss to the State in fiscal year 1982–83 of $227–247 million. These figures do not take into consideration the many indirect affects such as: personal income taxes, employment figures and sales taxes paid by individuals.

It is a fact, however, that every one dollar drop in the price of oil costs Louisiana in excess of $31 million in severance taxes and royalties alone.

The Oil and Gas Industry drilled a record number of wells in Louisiana in 1981 with 5,379 wells drilled, topping the old mark of 5,344 set in 1964. But the rate of growth in the drilling industry began to slip late in 1982, which reflected the first decline in drilling activity since 1973. The latest figures available (April 25, 1983) show that there are 278 active drilling rigs today as compared to 362 rigs employed during the same period of 1982. These low figures show a significant improvement over those figures in early 1983, which was below the 250 level.

Our industry has demonstrated that we respond to economic incentives and disincentives. For instance, the State of Louisiana's oil production peaked in 1971 at just over 800 million barrels. By 1979 this production had declined to just over 400 million barrels per year, a loss of 50 million barrels per year during that period. At that rate of decline, Louisiana would have been essentially out of the oil producing business in another eight years. With higher prices allowed under the NGPA and the decontrol of crude oil prices in 1980 we witnessed a great upsurge in domestic oil and gas drilling. As a result of these incentives, Louisiana stabilized her crude oil production at 1978 rates for the last four years. The same thing is true for natural gas.

At the end of 1981 there were approximately 4,600 rigs operating in the United States. Due to the decline of oil prices from $40 to $32 and now to $29 we have seen a decline in rig activity to approximately 3,300 rigs operating at the end of 1982. This same situation exists in Louisiana as I mentioned earlier in my statement. This situation not only affects producers but drilling contractors, service companies, transport companies, tugs and barges and all other support services. Many of our large drilling contractors currently have more than 50 percent (and in some cases 75 percent and more) of their rigs stacked with no jobs in sight.

Sanford McCormick, a large well-known and successful Houston Independent oilman, who has historically been very active in our State, has said that public investment money for oil drilling ventures has essentially disappeared. This has been echoed by everyone in the business. Reports indicate that all public drilling funds were down during 1982 by over 50 percent and 1983 could be even worse. Although this is the public sector, indications are that the private sector is down by a like amount. There is no question but that the public has been receiving very negative information regarding our business. Any adverse action by the Congress will be perceived as another negative by all parties and will definitely further hurt the oil and gas business in Louisiana as well as in the rest of the country.

As mentioned earlier, the oil and gas industry in the State of Louisiana employs in excess of 165,000 people—not including the multiplier effect of other related industries. However, today the employment situation in the state is bleak to say the least. For instance, in all parishes dependent on the oil and gas industry, the unemployment rate is in the 12-13 percent level—above the national average.

The picture that has been painted in this testimony is one of an industry which has profoundly impacted the character and direction of the Louisiana economy. I would like to summarize with the following points:

Among the states in the United States, Louisiana is a major petroleum producer. It is the third largest producer of crude oil and the second largest producer of natural gas.

Over the 1955-1980 time period, employment in the oil and gas extraction sector grew faster (115 percent) than employment in the total manufacturing sector (77 percent).

Louisiana is the only state in the United States that every parish (county) has oil and/or gas production.

State government revenue in Louisiana is dominated by collections from the petroleum industry. Collections from taxes royalties, rents and bonuses account for more than 50 percent of all undedicated funds collected by the State Treasury.

More than 95 percent of all wildcat wells in Louisiana are drilled by the independent oil and gas industry.

Mr. Chairman, the independent oil and gas sector is an important one indeed. However, due to extraordinary risk and dollar investment, it is absolutely imperative that the existing exemptions for independent producers, which is the subject of these two days of hearings, remain.

Mr. ANTHONY. I would like to thank all of the witnesses for appearing.

I just did a quick calculation.

Mr. Harmon, you are a little bit over 20 times larger than your bordering State just north of you in the matter of oil and gas.

I was informed yesterday by a witness representing 11 Rocky Mountain States to the effect that they had an awful lot of independent oil producers out there. I expressed to that witness I had a distorted viewpoint of this area of the country. I thought it was mostly majors out there due to the expense involved in drilling in a mountainous region.

I must admit, being a bordering State, we have always been somewhat jealous of the riches in Louisiana, inasmuch as your budget for education in Louisiana is larger than the entire budget for the State of Arkansas. I wish we had as much natural riches as you do.

But I have also had a distorted viewpoint of Louisiana. I thought it was mostly the large oil companies that were producing the natural resources down there.

Mr. HARMON. There it is mostly offshore that majors operate. Independents operate strictly—well, in the shallow waters and onshore.

Mr. ANTHONY. Have you seen over the past few years the majors in Louisiana abandoning certain fields and having those fields taken over and opened by independents?

Mr. HARMON. Absolutely, because of its not being financially feasible for a major to do it, and the independent can do it because of the lower overhead.

Mr. ANTHONY. The major companies have a costlier operation, then, and when wells get down to a certain point it falls below their unit cost available to operate?

Mr. HARMON. I would assume with their AEFE's, once they reach a certain level, it is not economically feasible for them.

Mr. GLOVER. I can give you an example of one that recently occurred in Illinois.

Marathon Oil Co. was operating a field that has been producing since 1906. There are 430-something wells in the pool, very shallow wells, 300 feet deep. The total gross production from those wells was running 160 barrels a day. Marathon sold it. An independent bought it and he will make a few bucks with a lot of struggle and a lot of work. But a major could not operate something like that. Electrical systems were all in decay.

Mr. ANTHONY. Mr. Soaper, I thought Arkansas had a high ratio of stripper wells—Kentucky apparently has a larger percentage.

Mr. SOAPER. We have our share of them. We are lucky. Down through the years we have been in the oil-producing areas. We are getting a lot of people coming in because we have a lot of shallow targets. With the situation the way it is today, it is easier, less costly to drill in Kentucky than a lot of the other States.

Mr. ANTHONY. We talk about the uncertainty that hearings like this may cause in the industry about the possibility of a freeze of future tax reductions or repeal of certain tax preferences that are in the code.

I would like to ask one broad question. Then I would like each of the witnesses to give their own individual responses as to what they think the economic impact would be in their State, and as to what they think would happen if all preferential provisions in the code regarding special treatment of independent oil producers and royalty owners were repealed. Keep in mind it is irrelevant whether we're repealing these provisions to try to bring tax equity to integrated companies and independents, or to generate revenue to balance the budget.

Mr. GLOVER. I would be happy to start. I think it would be a disaster in Illinois. I think ultimately your revenues would be cut because of the marginal stripper properties, you would just shut them down.

Mr. ANTHONY. So in your opinion, the preferences that are in the code are working?

Mr. GLOVER. Yes, they are working, very definitely.

Mr. ANTHONY. You think you have demonstrated by your testimony the wisdom of the Congress in providing these independents, you are seeing tangible results of those tax preferences, put into place in your State.

Mr. GLOVER. Yes.

Mr. MORGAN. Mr. Chairman, I think the Ohio situation was very graphically illustrated say since the 1970's, when the price of oil was at a high level, with the advent of the NGPA and so forth, the level of activity in Ohio did indeed reflect growing investor participation—certainly there was incentive because of the price of the product. I won't deny that.

But as I pointed out in my testimony, Ohio producers deal with a certain class of investor. And this is the small investor, the investor that doesn't want to risk large sums of money. He buys small interests in drilling ventures, or he buys small interests in individual wells. These type of investors are so dependent on that incentive provided by the various tax treatments, the IDC's especially, that I think without that preferential treatment, we would see funds for Ohio drilling just totally dry up—and since we are dependent on about 70 percent of our capital from that source, I would say that we probably would see an extremely substantial decline in Ohio drilling, and people would get out of it, just simply drop out of business.

Mr. **Anthony**. Thank you, Mr. Harmon.

Mr. **Harmon**. I agree with what he just said; particularly we have found that public drilling funds are down now to probably the lowest level they have been in the past several years. A lot of that is due to the state of the economy of course. A lot of it is due to the fact that they keep hearing disincentives being offered to the oil and gas industry, and why go into that area.

So I think you would see drilling funds, number one, that would dry up to almost nothing. You have a lot of independent producers, particularly in Louisiana, that are operating very marginal wells at this time. Any of those incentives, particularly the intangible drilling costs, and if a few of those be taken away, you would have to see them abandon wells and go out of business, and they could do it in other areas.

Mr. **Soaper**. Essentially the same. We have had quite a bit of fluctuation in the industry, because the price was going up. There was a lot of information out that it would be $43, $50, $60 a barrel. That attracted a lot of attention. We heard that for 4 years. When reality finally set back in, the price started coming down, we are having a hard time with all the flush money, the flush money coming in when everything looked great. Now we are having to go back to where we were in the early 1970's and we are starting to produce again.

We will survive this thing. We have survived through the 1960's, the late 1960's and up to the early 1970's. It is a struggle right now in Kentucky to raise money. Our people go to Florida, they go all over, all the outside producing States. That is where most of the money comes from. And any time you get any adverse publicity of what is going to happen taxwise or anything else, it just slows those people down. They are waiting to see what is going to happen.

Mr. **Anthony**. Well, I think the panel very well articulated the justification for the special treatment of independents and what the consequences would be in various States.

I think you have made a valuable contribution, not only to the regions you represent, but you have also made a valuable contribution to the subcommittee in our efforts to write a report that will be prepared for the full committee regarding preferential tax treatment.

I thank you personally, and also for the rest of the members of the subcommittee who cannot be here.

Our next panel, and our final panel of the afternoon, is Mr. Cornelius. I understand Mr. Dwyer is a friend of the chairman of the subcommittee, Mr. Rangel. Unfortunately, he cannot be with us.

Mr. Edward H. Ward, Palm Desert, Calif.; Jack B. Riley, CPA, Ardmore, Okla.; Walter W. Brudno, counsel of three different companies.

Gentlemen, we have copies of your testimony. We will be pleased to accept the full printed text in total for the record. You are permitted at this time to proceed as you desire.

## STATEMENT OF CORNELIUS J. DWYER, PRESIDENT, QWAD ECONOMICS, WASHINGTON, D.C.

Mr. DWYER. I am Cornelius J. Dwyer. I am an economic consultant based in Washington and specializing in energy. Because of my intense concern about the vulnerability of the United States to disruptions in its energy supply, I wished to present my views on the subject to the subcommittee for its consideration and I appreciate the opportunity to do so.

At the outset, I want to stress I am not in any sense a tax expert. Consequently, I am not qualified to speak to the specific tax provisions which are the subject of this inquiry.

What prompts my interest in these proceedings is my conviction that an incentive tax policy is a vital element in eliciting adequate investment in domestic energy exploration and production, and my long experience in assessing world energy supply and distribution and in planning to meet free world energy supply needs under emergency conditions.

A brief summary of my background is perhaps appropriate.

After World War II service as a glider pilot, I was commissioned a Foreign Service officer, and assigned to work on coal and petroleum at the American Embassy in London. At that time the United States and Britain controlled most of the oil moving in international trade through their multinational companies, which also owned or leased the tankers in which the oil was moved. The Netherlands, which owned 60 percent of the Royal Dutch/Shell group, and France which had nearly a quarter share of the Iraq Petroleum Co., also had interests which had to be respected.

Nevertheless, we and the British bore the primary responsibility for insuring the supply of oil to the free world in the event of an emergency. I was deeply involved then and later in the planning for any conceivable crisis which would cause, or be aggravated by, oil shortages or supply disruptions.

The first of these was the Korean war, followed a year later by Mossadeq's nationalization of the Anglo-Iranian Oil Co. During the first part of this period I was assistant chief of the petroleum branch of the Economic Cooperation Administration, the agency which administered the Marshall plan, and on various committees of Interior's Petroleum Administration for Defense.

In the middle of the Korean war, I was detailed to the Paley Commission, the President's Materials Policy Commission. The President was Harry Truman and the years were 1951–1952. There I was in charge of the petroleum section, trying to look forward to the early 1970's.

Although the U.S. oil position appeared tight in 1951, we recommended against the $40 billion in 1946 dollars crash program to develop oil shale and oil from coal, which had been urged by former Interior Secretary Ickes. Making petroleum liquids from oil shale economically then appeared just around the corner, as it had seemed in the 1920's to an earlier commission. Two generations later, we have yet to come near that corner.

Although we recommended against such a crash program, we also urged that the U.S. energy position be reassessed if the Nation ever became dependent upon imports for as much as 20 percent of our oil needs. The Commission's projections of U.S. oil demand in 1970 turned out amazingly accurate, in part because of compensating errors. By that year, the Nation was more than 20 percent dependent upon foreign oil and quite complacent about it.

After the Paley Commission, I returned to ECA, this time as chief of the petroleum branch, and resumed working on PAD committees. I also took part in the establishment of the NATO petroleum planning committee and served as alternate U.S. delegate, as well as chief U.S. delegate to the oil committee of the OECD [Organization for Economic Cooperation and Development].

In 1960 I became regional petroleum attachê for the Middle East, based in Beirut in the very building blown up 3 weeks ago. I was thus on the spot when OPEC was founded. I'd like to say more about OPEC later.

After a period outside the Government, I returned in the late 1960's and worked for the Federal Energy Administration and the Department of Energy, this time primarily in the domestic side of the energy business. I played a part in developing DOE's short-term energy forecasting model, and was a regular Government observer at the meetings of the IPAA's Supply and Demand Committee.

After retiring from the Government in 1980, I was invited to become a full member of that committee.

Since others are addressing the effects and propriety of the specific tax provisions under scrutiny, I will limit my remarks to the necessity, as I see it, of directing all Government policy, tax policy included, at strengthening our energy productivity. We are still dependent upon others for too much of our oil supply.

The political instability and uncertainty in the Middle East with which we are constantly grappling could result in accidental or purposeful interdiction of oil supplies from that area at any time. We must recognize some hard facts which will govern our energy security in the coming years: first, the long-heralded synthetic fuels industry and other widely publicized energy alternatives will not make meaningful contributions to our energy needs for 15 to 20 years at best. Therefore, conventional oil and gas, augmented by coal and nuclear, will continue to dominate the energy mix needed for economic growth and national security.

The United States still has significant unfound and undeveloped oil and natural gas resources, but they exist in geologic formations which will be increasingly costly to explore, develop, and produce. The challenge of minimizing our important dependence will involve unprecedented capital requirements in the rest of this century.

We should not be lulled into a false feeling of security by the fact that we are now receiving about a quarter of our crude oil imports from our next door neighbors, Canada and Mexico, and only about 18 percent from the Arab members of OPEC. We are tied by solemn treaties and covenants, NATO and the International Energy Authority [IEA], which bind us to share the burdens of any supply disruption with other free world nations.

As you are aware, those nations shared with us when we and the Netherlands were the subjects of the Arab oil embargo in 1973. Nevertheless, according to the rules of the IEA agreement the more of our own energy supplies we can provide, the lighter the burden of any conceivable supply disruption upon us.

And now, if I may, I'd like to give you some history of the events which led to the foundation of OPEC in September 1960.

By the late 1950's, the major international oil marketing companies had come under intense price pressure in their overseas markets, particularly in Europe. Part of this pressure came from newcomers with concessions in Venezuela and Libya, who had found oil and then discovered that they could not bring it into the United States as they had planned because of President Eisenhower's imposition of an oil imports quota in 1957. And part came from some of the marketing majors' own partners in joint Middle East production, partners who were long on crude oil and short on markets.

The majors had always been accustomed to raising and lowering posted prices according to their own views of the market, without consulting host country governments.

But by 1960, things had changed in the oil source countries and changed more than some people in the home offices of the major companies seemed to realize. Venezuela had been trying for years to organize its fellow oil-producing countries. Many Venezuelans and quite a few Arabs had by then been educated as petroleum and chemical engineers or in business administration at American colleges. They knew how we thought.

But not a single chief executive officer of any of the major oil companies, American, British or British/Dutch, had visited the Middle East in the entire 5 years prior to 1960. Critics said that they still regarded the Arabs as the same illiterate Bedouins they had first met in the 1920's and 1930's.

The majors finally announced a cut in the posted price of Middle East crude oil in August 1960. The Venezuelans and some key Arabs sprang into action. And the founding meeting of OPEC was held in OPEC a month later. Nothing has been the same in the international oil trade since.

The organization proceeded slowly and cautiously, first building its technical skills. The academic economists scorned it, saying that cartels simply can't work.

I was reminded at the time of one of my first lessons in aerodynamics. According to the supposed laws of that science, bumblebees can't fly because their wings are too small compared with the weight of their bodies.

Obviously the laws of aerodynamics needed some revision; so did the laws of economics. Cartels are always on the verge of falling apart, like a novice on a unicycle. But they have a long history of surviving, especially when they are completely legal and supported by the Government.

OPEC is an organization devoted to furthering the economic interests of its members. It has been responsible for very large price increases but it is not a political group and is not responsible for any of the frequent supply disruptions we have felt in the past 30 y[illegible]

[illegible]e Central Intelligence Agency has listed 13 of those, which I shall summarize here.

[The information follows:]

<table>
<tr><th>Period</th><th>Duration</th><th>Magnitude of Supply Shortfall (Millions of barrels a day)</th></tr>
<tr><td>Mar 51-Oct 54</td><td>44 months</td><td>0.7</td></tr>
<tr><td colspan="3">Mossadeq's Nationalization of Anglo-Iranian Oil Co.</td></tr>
<tr><td>Nov 56-Mar 57</td><td>4 months</td><td>2.0</td></tr>
<tr><td colspan="3">Suez War; closure of canal, Iraq Petroleum Co. (IPC) pipeline to Lebanese port of Tripoli damaged in Syria; Saudi Arabia embargoes United Kingdom and France.</td></tr>
<tr><td>Dec 66-Mar 67</td><td>3 months</td><td>0.7</td></tr>
<tr><td colspan="3">Syrian Transit Fee Dispute; IPC pipeline shut down</td></tr>
<tr><td>Jun 67-Aug 67</td><td>2 months</td><td>2.0</td></tr>
<tr><td colspan="3">Six-Day War; IPC pipeline and Trans-Arabian Pipeline shut down; shipments to United Kingdom, West Germany and United States embargoed.</td></tr>
<tr><td>Jul 67-Oct 68</td><td>15 months</td><td>0.5</td></tr>
<tr><td colspan="3">Nigerian Civil War; Shell and BP had to stop producing.</td></tr>
<tr><td>May 70-Jan 71</td><td>9 months</td><td>1.3</td></tr>
<tr><td colspan="3">Libyan Price Controversy; Libyan production reduced; TAPline in Syria damaged by sympathizers.</td></tr>
<tr><td>Apr 71-Aug 71</td><td>5 months</td><td>0.6</td></tr>
<tr><td colspan="3">Algerian-French Dispute over proposal to nationalize 51% of French companies.</td></tr>
<tr><td>Mar 73-May 73</td><td>2 months</td><td>0.5</td></tr>
<tr><td colspan="3">Lebanese Political Conflict; disruption of shipments through both IPC pipeline and TAPline.</td></tr>
</table>

| | | | |
|---|---|---|---|
| Oct 73-Mar 74 | 5 months | 1.6 | Arab-Israeli War; Organization of Arab Petroleum Exporting Countries (OAPEC) (Not OPEC) embargoed exports to United States and The Netherlands; oil shipments through Suez Canal halted. |
| Apr 76-May 76 | 2 months | 0.3 | Civil War in Lebanon; Iraq cut shipments through IPC pipeline. |
| May 77 | 1 month | 0.7 | Saudi Oil Field Fire (Abqaiq). |
| Nov 78-Apr 79 | 6 months | 3.7 | Khomeini Revolution in Iran; unrest in oil fields. |
| Oct 80-date | 31 months<br>(to date) | 1.3 | Iraq-Iran War |

Mr. DWYER. In my opinion, the OPEC cartel will continue and will achieve to a considerable extent its economic goals. The latest indications are that its $29 a barrel price for Saudi Arabian light, the so-called marker crude oil, is holding. And consumers shouldn't complain; considering that the value of the dollar has been declining, this represents a substantial reduction in the price of crude oil in constant dollars.

Since U.S. prices are related to OPEC prices, this means, however, a drop in the real price domestic explorers can expect to get from new discoveries. Further cuts in after-tax profits—we must always add in this high-risk business "if any"—would further discourage exploration right here at home.

Thank you.

Mr. ANTHONY. Mr. Ward.

## STATEMENT OF EDWARD F. WARD, JR., PALM DESERT, CALIF.

Mr. WARD. I am Ed Ward from Palm Desert, Calif.

I am a professional manager and independent producer. I manage for other people about 20,000 acres of land. I take part in three or four productions per year.

I want to answer your question why this meeting is being held.

The windfall profits tax is inherently bad policy because it is inequitable to the same parties to the same contract. It is a bureaucratic and inequitable disaster that provides no money to the United States or to its citizens. With the falling price of oil, the increasing inflation factor, there is no—and the fact that the profits are falling, and therefore people don't have income, then you add to that some of the things I am going to show you, and you find out we are really not making any money because it costs us too much to operate this.

Now, I have some examples. But the important thing to understand, that a lot of people don't, is in the oil business when we put something together, it involves normally 50 or 60 people to any given operation. So when we look at any of these examples, or the exhibits that I have here, you have to realize that I am talking in terms of 10 to 15 to 20 to 30 people when these things happen.

Now, the exhibits simplified say this: That there are large loopholes in the windfall profits tax that I can drive a truck through to get exemptions.

Second, there are parts of the windfall profit tax that allow one taxpayer to see the tax rates of another taxpayer, and that second taxpayer can do nothing about it. Now, there are ways this might be changed, but the only ways they can be changed will complicate what is already an almost impossble situation to understand.

You also have to understand those people that I am talking about, the 50 and 60 people to the contract, many of them, this is not their primary occupation and therefore they have to try and hire somebody like me that tries to understand it. A few more changes and I won't be able to understand it.

There is a lot of examples I can give you as to—if you like I would be happy to explain that simplified version that I attached. But as you see, it is difficult. There are a lot of examples I can give you as to why it is a bureaucratic disaster.

Probably the best one I can give you is the case of the entity for whom I collected all of the 6248's in May 1982. I filed these, and they showed that that particular taxpayer had overpaid windfall profits tax by $1,600. Please understand, this is what is happening to probably 40 people at the same time.

We filed. We got our refund and interest back from the IRS in November. And in December of 1982, I get an amended 6248 from one of the producers. It says the first one they sent to us said we had taken too much of a credit by $190. Well, there was no way we could tell this, because we didn't do this. And at any rate, we dutifully file our forms, pay the $190, and then in April, while we are paying our income taxes, we get a bill from the IRS for $44,000. Why?

Because the IRS is so completely confused with this thing that they are treating it that we were supposed to pay all the excise taxes. They didn't even understand the company was supposed to pay it.

Now, believe it or not, the same week that we received the $44,000 bill from the IRS, which—understand, this taxpayer was only $30,000 in the first place, but now taxes and penalties—you can see how it builds up.

There is only one way to solve the problem.

Mr. ANTHONY. Before you proceed, I would like to ask one question.

You are saying that the example you have set out has not been resolved with IRS?

Mr. WARD. The example I have set, I have spent 2 days typing the answer back to the IRS to try to explain to the IRS why the taxpayer doesn't owe any money. The IRS has yet to reply back to me.

Mr. ANTHONY. And you are saying that all of this is the result of mess-ups under form 6248?

Mr. WARD. I am saying it is inherent in the system of the thing, sir.

You see, when you put one of these things together, you have 60 people, 80 people. A 6248 has to be sent to them; it has to be held and at the same time the IRS has to take that and send to the district office.

The district office treates it as an excise tax.

The IRS is trying to put the two things together and at the same time we are getting new forms from the producers to refile, so the thing keeps building on top of itself.

Mr. ANTHONY. What I would like to do is make a request of staff, to be approved by the chairman of the subcommittee and/or the full committee, to request the IRS to give their account of this and make it part of the record along with the testimony from this witness.

Mr. WARD. That is fine with me, sir.

Mr. ANTHONY. I think it may help this committee to take a look at not only the tax policy but it may also help give us an opportunity to take a look at the procedure by which it is being administered, and who knows?

We may be able to solve some of it for you. It is confusing the way you are laying it out.

Mr. WARD. I am sorry. It is inherent in the issue. What happens is, the producer, in terms of the 6248's—they have to be amended. Once the producer amends it, all the taxpayers have to amend because there are so many people to any given entity, when you have any amendment you can have 120, 150 new tax returns that have to be filed. It just builds on top of itself.

Mr. ANTHONY. Before I interrupted, I think you were getting to the nitty-gritty in giving us solutions to the problem.

Mr. WARD. The bottom line is that you cannot amend the law any further without even complicating it further.

The only answer that I can see is for a Federal severance tax of 5 percent to be attached to a 5-percent import tax. It is virtually impossible for any industry to apply the tax rates with the entities, with the different types of oil, without it being a virtual catastrophe nobody can understand.

That is the bottom line. That way the Government will get some money. There will be no abuses. It has been done for years. The only thing I worry about is once it is 5 percent, will it be abused? Will it be raised?

[The statement and attachments follow:]

## STATEMENT OF EDWARD F. WARD, JR

ly name is Edward F. Ward, jr. I am a Professional Mineral Manage nd Independent Producer. In the managerial position, I either directly upervise or provide advisory assistance on nearly 27,000 acres for var-ous entities. In the production area, I take part in three or four ex-lorations per year. I am here representing only myself.

rom direct daily experience in these occupations, I can state without eservation the Windfall Profit Tax is a total bureaucratic inequitable isaster that is getting worse by the day. I will try to show by ex-ibit and example why I can be so categoric. It I succeed and the nfairness and chaos I demonstrate is added to the reduction in WPT evenues because of lower oil prices and to the loss of income taxes on rofits and to the direct administrative costs to government and busi-ess, the only conclusion can be that the WPT is severely hampering ne of our Country's vital industries while providing no net monetary enefit to its Citizens.

s a result, I am hopeful the Committee might positively consider the ecommendation that the WPT be repealed and replaced with a 5% Federal everance and Import Tax.

n considering the exhibits and examples, I ask you to fully under-tand the oil business is almost always conducted under a "perpetual" ype lease contract where there are a great number of entities that make p both "parties" to the agreements. Additionally, a large number of hese entities do not make this their primary occupation. Thus, when say either "mineral owner" or "producer/working interest" in regard o any single "property", I am normally talking about 20 or 30 entities or each. Further, a substantial percentage of these numbers cannot ossibly afford the expense and time necessary to understand this incred-bly complex tax.

xhibits A & B are attempts to provide a simplified explanation of the mmense inequities and frustrations of the tax as well as demonstrate ome of the factors which make proper contractual decisions difficult f not impossible.

will be happy to more fully explain these; however, the most impor-ant points to get from them are: 1.) There are large escape holes in he tax for certain specific entities; and, 2.) the provisions of the tax llow one taxpayer to make a tax decision which while beneficial to him r herself punishes another taxpayer, under an unalterable contract, o an adverse tax rate.

ny successful efforts to correct this situation will add greatly to the osts of government and business administration.

These exhibits are, for the most part, based on actual cases; but, the size of the property or numbers of entities involved has been reduced to simplify the explanation. The examples that follow are from my personal experience. They are what actually happened.

In the first case, an operator failed to file the correct base price on a "NEW" well. This wrongfully increases the WPT. The operator was contacted to refile properly. The purchaser was contacted to recompute the correct tax. A tax refund request was filed and paid by the IRS with interest.

Without considering costs, my time alone, for just one client in this case, was one day. There are 14 other entities involved in this incident. That is a total of 15 days of non-productive work, plus costs, and 15 tax returns and refunds to be processed by the IRS.

In another case, one of my clients owns a .000056 interest in a tract where there are 30 entities involved in the agreements on a very small producing well where the purchaser was changed during the year.

This means 120 6248 forms have to be computed and mailed. (60 to the entities and 60 to the IRS.) Each one has to be used by each entity to compute the amount of WPT under or overwithheld and each one has to be processed all over the nation by the IRS.

The postage bill alone to the private interests was $12.00. My client's total involved WPT was 5¢.

I can give many more cases; but, this final one should suffice to make my point.

In May of 1982, all the 6248 forms were collected and filed for one client for the year 1981. The computations based on these 6248's indicated an overwithheld amount of $1,698.00. The IRS made the refund in full plus interest in November of 1982. Then, in December of 1982, a revised form 6248 was received from one purchaser. It reflected the originally filed form had an overstated overwithheld amount of $190.00. In essence, it showed the taxpayer, thru absolutely no fault of its own, had taken a credit of $190.00 too much.

So, in January of 1983, the revised 6248 was filed with payment of the $190.00 and a request to be advised of the amount of interest due. In April of 1983, the IRS sent a bill for $44,934.00 ($31,444 tax, $8,646 penalty and $4,934 interest)

Why? Because, the IRS did not take into account the previously filed 6248 forms confirm payment of the original tax by the purchaser. This will obviously take more time and money and the matter has not been settled yet.

As if this were not enough. In the same week's mail as the $44,000 bill, the taxpayer received another revised 6248 from a different purchaser for the same 1981, a revised 6248 for 1980 and a new 6248 for 1982 that was wrong.

To add to this, the IRS sent a request for the payment of excise taxes for the final quarter of 1982. (The client is not responsible for these as they are not applicable to taxpayers filing annual 6248 forms; but, there does not seem to be any way to convince IRS computers of this. Believe me I have tried and continue to try.)

Please do not forget taxpayers must do all this work and factor it into the normal income tax work and remember this is not in many cases their primary occupation.

And, as I have stated, any solution to pending issues will only make matters more complicated and costly.

Frankly, I do not understand how the banking industry was considered incapable of supporting the expense and detail for administering a simple flat 10% tax rate while the oil industry is supposed to be able to handle all the costs, work and complications for a discriminatory tax based on three types of oil wherein the taxes for various entities to a single contract can vary from 0 to 25 to 30 to 50 to 60 to 70 percent.

Amendment cannot solve and will only worsen the problem. The only conceivable solution is to repeal the WPT.

I don't think anyone is naive enough to think this possible without a substitute revenue producer. Though, the idea of a 5% Federal Severance Tax is anathema to my whole philosophy and I fear the possiblity of its future political abuse, I have suggested it because it is a tried, simple method which will provide constant revenue, be easily understood, collected and enforced, difficult to abuse and inexpensive to administer while being fair to all.

It should be tax deductible and applied to all domestic oil with the sole exception of that guarded by treaty or owned by governmental or charitable organizations; and it should be combined with a 5% import tax.

Truly, for proper economics, it should be further combined with total deregulation of natural gas together with a 5% severance tax on it and coal.

Probably the only thing wrong with this suggestion is that it is too simple.

Edward F. Ward, jr.
P. O. Box 251
Palm Desert, California 92261-0251

619-346-1931

EXHIBIT B

O & I ALL SAME OIL FROM SAME RESERVOIR IN ADJOINING TRACTS

X DIFFERENT FROM ABOVE RESERVOIR BUT SAME OIL/RESERVOIR IN ADJOINING TRACTS

| "LEASE PROPERTY" | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 1978 Production Qualified | STRIPPER | | STRIPPER | | OLD | | OLD | |
| Operator and W. I. | MAJ. w 45% IND.W.I. | | IND. w 45% MAJ.W.I. | | IND. w 45% MAJ.W.I. | | MAJ. w 45% IND.W.I. | |
| Property I. D. # | (Elect)<br>X | 1<br>O | (Not Elect)<br>X | 2<br>O | (Elect)<br>X | 3<br>I | (Elect)<br>X | 4<br>I |
| Major Oil Company (MAJ.) | 25% | 60% | 60% | 60% | 25% | 70% | 25% | 70% |
| Independent (IND.) | 25% | EXEMPT | EXEMPT | EXEMPT | 25% | 50% | 25% | 50% |
| Mineral Owner (ROY.) | 25% | 60% | 60% | 60% | 25% | 70% | 25% | 70% |

LEGEND

O - Stripper Well to Reservoir A Completed in 1975 (10 BBLs per day 1977)
I - Old (Tier 1) Well to Reservoir A Completed in 1975 (11 BBLs per day 1983)
X - New Well to Reservoir B Completed in 1983
W. I. - Working Interest

NOTE:
Tax rate for MAJ & ROY determined by who producer in a stripper - 25% in 1 with MAJ or 60% in 2 with IND Qualified Production Determines IND Election - 25% for all in 3 if OLD but 60% for MAJ & ROY w EXEMPT for IND if STRIPPER as in 2

(RATES APPLICABLE TO WELL UNDER FOR INTEREST TO LEFT AS IN EXHIBIT A)

## EXHIBIT A

IT DOES NOT MAKE ANY DIFFERENCE HOW MUCH THE WELL IS PRODUCING

X & O ALL THE SAME OIL FROM THE SAME RESERVOIR IN ADJOINING TRACTS

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| "LEASE PROPERTY" | ■ | | | | □ | | ▭ | | ▬ | |
| 1978 Production Qualified | NONE | | NONE | | STRIPPER (From Reservoir A) | | STRIPPER (From Reservoir B) | | STRIPPER (From Reservoir B) | |
| Operator and W. I. | IND. w. MAJ. participate | MAJ. | MAJ. w 45% IND.W.I. | | MAJ. w 45% IND.W.I. | | IND. | | MAJ. | |
| | (Farmed out by MAJ.) | X | | X | | O | | ? | | ? |
| | | | UNITIZED IN 1982 | | | | | | | |
| Property I. D. # → | 1-A<br>X | 1-B | X | 2 | X | 3 | (Not elect)<br>X | 4 | (elect)<br>X | 5 |
| Major Oil Company (MAJ.) | N/A | 25% | 60% (?) | 60% (?) | 60% | 60% | N/A | N/A | 25% | 60% |
| Independent (IND.) | 25% | N/A | EXEMPT | EXEMPT | EXEMPT | EXEMPT | EXEMPT | EXEMPT | N/A | N/A |
| Mineral Owner (ROY.) | 25% | 25% | 60% (?) | 60% (?) | 60% | 60% | 60% | 60% | 25% | 60% |

(THE ABOVE ARE THE RATES APPLICABLE TO THE WELL THEY ARE UNDER FOR THE INTEREST TO LEFT)

**LEGEND:**

- O – Stripper Well to Reservoir A Completed in 1975
- X – New Wells drilled to same Reservoir A Completed in 1983
- ■ – Stripper Well to Reservoir B Completed in 1975
- W. I. – Working Interest

**NOTE:**

ROY & MAJ 25% tax on $\frac{1}{2}$ of lease & 60% tax on other $\frac{1}{2}$ of property 1 & 2
IND EXEMPT on $\frac{1}{2}$ of same lease and 25% tax on other $\frac{1}{2}$
ROY 25% tax on NEW well in 5 but 60% tax on same kind of NEW well in 4 because of type of operator
If MAJ had IND. W.I. in 5 would force 25% Tax where otherwise would be EXEMPT

Mr. **Anthony**. If I understand you correctly, you believe we should repeal the windfall profit tax, and put in a 5-percent excise fee?

Mr. **Ward**. Not excise, severance.

On everybody, every kind of oil. Collect it at the wellhead the way every State does it. It is so simple.

Right now I would guess the IRS is going to spend at least the amount of money that we are paying in to afford the field agents that are going to be necessary to collect this, and that doesn't count what it costs us in private industry to administer this thing.

Mr. **Anthony**. Let me tell you, you have a strong supporter in that. As a matter of fact, when the windfall profit tax was being debated in the Congress, I was not on this committee at that time, but I took an active role in trying to do exactly what you are advocating.

If it is going to be a severance tax, in effect, let's call it that. Let's make it that and let's try to bring it in as simply as possible, bring in the same amount of money. Why that was not done I cannot tell you.

I know that it got tied up in political decisions, but there were many of us in the Congress that represent oil producing areas that thought that was the best way to go. At that time, the only way we were going to get decontrol was to give the President his slice of the increased revenues through a tax.

So maybe we can, with your assistance, with your testimony, maybe we have helped make a record for the fact that administratively it is a nightmare and we ought to take a close look at it and do something about it.

Mr. **Ward**. Thank you.

Mr. **Anthony**. I appreciate your testimony. I just represented my personal CPA back in my hometown. Every time I go home that is exactly what he tells me. I am going to give him a call and send him a copy of your testimony.

Our third witness is Mr. Jack B. Riley.

## STATEMENT OF JACK B. RILEY, ARDMORE, OKLA.

Mr. **Riley**. I want to express my appreciation for the opportunity to be heard today. If there is an opportunity to strike a blow against the windfall profit tax, I want to do that too.

As I left I received some 1980 amended 6240 forms for clients of mine. We have to go through the same process Mr. Ward described 2 years later.

There is a virtual nightmare of paperwork involved with the accountants, the attorneys, and the individual producers. We are never sure if we have the exact numbers. We are never sure how correct those numbers we have are going to be.

On a larger scale, I am here today to address the subcommittee as a representative of my clients in southern Oklahoma. Carter county, in which I reside, is the largest producing county in the State.

Oklahoma's production is approximately 90-percent stripper well. Those are controlled by independent oilmen. These people recognize this subcommittee has been charged with the difficult task of oversight of energy taxation. This is a most unusual period of time for the energy producing industry.

The price of the product is falling; the cost of producing the product is climbing; there is a worldwide crude oil surplus; and, lastly, they are portrayed as ruthless megamillionaires on weekly television shows.

Few images could really be further from the truth. The independent oilmen work hard, long hours of the day and night for the challenge of discovering and producing oil with a reasonable profit incentive.

It should be understood at the outset that the reasonable profit incentive is a necessary element at all levels of oil exploration and production. From the geologist to the refiner, without the profit, the wheels of energy production would come to a halt. I assume that it is this subcommittee's intention to consider additional taxation of the energy industry in order to raise the Federal revenues and to lower the size of budget deficits.

But, in the free enterprise system there are many cause/effect relationships. So that the effect of energy taxation cannot be isolated just to the result of increasing Federal tax revenues.

Instead, the consequential considerations on future company drilling budgets affects capital investments, employment, production, and national defense.

The following testimony serves to present a short microeconomic background of the energy exploration and development industry and then discusses three tax increasing considerations, all of which affect the independent as opposed to the integrated oil companies: One, disallowance of current year intangible development costs; two, elimination of the statutory depletion allowance; and three, elimination of stripper production windfall profit tax rate. It is my goal to present documented evidence of the relationship between these three considerations and domestic development programs which eventually affect domestic production.

The quantity of domestic oil and gas reserves are known to be sufficient to meet this country's needs for well into the next century. What is lacking is the incentive to develop the production techniques. Only the ultimate maximization of domestic energy production, with equitable taxation, which allow for reasonable profits, will provide the required incentive for the Nation's independent oilmen to continue discovering those petroleum reserves.

The oil and gas production cycle begins with the drilling of an exploratory well. Exploratory wells are those drilled in a field which is not currently producing from the formation depth to which the new well is to be drilled.

Exploratory wells must be drilled before the field can be further developed, and before any crude oil or natural gas can be produced.

Independent oil companies drilled 83 percent of all domestic exploratory wells in 1981.

Exploratory wells are more risky than developmental wells, because the field is undefined. In 1981 only 46 percent of all exploratory wells were successful. The 54-percent unsuccessful exploratory wells cost almost $8.4 billion, of which 83 percent, or roughly $7 billion was incurred by independent producers.

During 1978, before oil prices were decontrolled, there were 11,239 exploratory wells drilled, of which 2,847 were successful oil wells.

In 1979, 1 year later, to allow for the 1978 successful wells to be producing for a full 12 months, the domestic U.S. production actually decreased 96.1 million barrels.

We were not discovering and producing oil as fast as we were using it. One full year after decontrol of oil prices, 1981, was a record year for exploratory drilling; 23,764 wells were drilled, of which 6,974 were successful, a 250-percent increase over 1978.

U.S. Department of Energy preliminary computations estimate the 1982 domestic production to be a record high 3,165 million barrels, a 723-million-barrel increase over 1981 thus leading us to the conclusion that there is a direct relationship between exploration and production.

In 1983 the oil drilling companies have encountered a difficult financial period. The worldwide crude surplus has caused the price to fall by more than 30 percent, to a level which does not produce sufficient net income to encourage continued drilling investments.

Consequently, the number of active drilling rigs has dropped from a December 31, 1981, record high of 4,530 to 1,860 on April 25, 1983.

Assuming that the direct relationship of drilling to production continues, the 1984 production could be expected to decrease significantly.

The ability to write off the cost of drilling an exploratory well is important to the independent oil producing industry. If the cost of a successful well were required to be capitalized, and subsequently amortized, funds to pay the initial incremental tax increase could only be provided through an additional drilling budget decrease. Predictably, the subsequent year's production would again decrease.

The same principle holds true for the independent producer statutory depletion deduction. Already scheduled to decrease to 15 percent by 1985, I estimate that the total elimination of the statutory depletion deduction would increase taxes by at least $1.4 billion.

Again, money to pay the tax increase could only be provided through decreases in annual drilling budgets.

The windfall profit tax reduced stripper rate is extremely important to independent oil producers because they have a disproportionately higher percentage of production from stripper wells.

In 1981 independents produced 18.4 percent of all domestic crude, but 41.6 percent of all stripper production; stripper production accounted for 14 percent of all 1981 domestic production.

To increase the stripper well windfall profit tax rate would make many of these wells, producing 1 to 5 barrels per day uneconomical and they would be shut in or capped from Kern County, Calif. to Carter County, Okla.

Furthermore, any new exploratory wells yielding only one to five barrels per day would not be completed. The investment in equipment and pipelines would not be cost justified considering the nominal after-tax income that the well would provide.

In my opinion, the aggregate windfall profit tax collected would actually decrease after considering the elimination of marginal stripper well production.

In addition to production, drilling activities mean jobs to millions of Americans.

A rough estimate is that for the 15 people directly employed to drill a well, another 45 are indirectly involved.

The 2,670 decrease in active drilling rigs has affected 160,000 people employed as engineers, roustabouts, salesmen, pilots, secretaries, and clerks all over the oil producing territory.

These are people used to hard work who desperately need for the industry to receive a shot in the arm, not another kick in the pants.

In summary, I submit that any legislation adversely impacting the independent producers: (a) drilling cost writeoff; (b) statutory depletion deduction, and/or (c) windfall profit tax rates would have a correspondingly adverse impact on the domestic energy production.

A continued decrease in domestic energy production, comparable to the 1978 through 1981 rate, would prevent this country from becoming energy independent. The consequential negative effect upon trade deficits, employment, and many other economic factors would be severe indeed.

This subcommittee is charged with the specific task of oversight of energy taxation. But on a much larger scale, you are responsible for striking a balance between Federal budget requirements and the profit incentive necessary to develop domestic energy production levels sufficient to achieve and maintain our independence from unreliable foreign energy sources. Without energy independence, our future national security is uncertain.

The first, last, and foremost consideration of this subcommittee should, and no doubt will be, the human effects/consequences of the proposals and/or recommendations which it makes as a result of these hearings.

This human effect which is, in essence the effect that this subcommittee's actions might ultimately have on people in New York City, Tampa, Jersey City, Knoxville, and Bakersfield, as well as those throughout the Nation, is one that must be considered also when any new tax legislation is proposed.

Additional taxes levied upon independent producers would take funds out of the borrowing, employing, exploring, developing, producing, and repaying cycle.

At some point, given current economic conditions, new taxes which remove additional funds from this cycle would inevitably lead to the financial collapse of the independent oil producing industry as well as the almost 1 million people it employs.

[The prepared statement follows:]

## STATEMENT OF JACK B. RILEY, ARDMORE, OKLA.

This subcommittee has been charged with the difficult task of oversight of energy taxation. This is a most unusual period of time for the energy producing industry - the price of their product is falling, the cost of producing their product is climbing, there is a worldwide crude oil surplus and lastly they are portrayed as ruthless mega-millionaires on weekly television shows - which millions of viewers select to watch and are eager to believe. Few images could be further from the truth - independent oilmen work hard, long hours of the day and night for the challenge of discovering and producing oil with a reasonable profit incentive. It should be understood at the outset that the reasonable profit incentive is a necessary element at all levels of oil exploration and production - from the geologist to the refiner - without profit the wheels of energy production, as with all other enterprises, would come to a halt.

I assume that it is this subcommittee's intention to consider additional taxation of the energy industry in order to raise the federal revenues and to lower the size of budget deficits. But, in the free enterprise system there are many cause-effect relationships. So that the effect of energy taxation cannot be isolated just to the result of increasing federal tax revenues. Instead the consequential considerations on future company drilling budgets effects, capital investments, employment, production, and national defense.

The following testimony serves to present a short microeconomic background of the energy exploration and development industry and then discusses three tax increasing considerations, all of which effect the independent, as opposed to the integrated, oil companies: (1) disallowance of current year intangible development costs; (2) elimination of the statutory depletion allowance; and (3) elimination of stripper production windfall profit tax rate. It is my goal to present documented evidence of the relationship between these three considerations and domestic development programs which eventually effect domestic production.

The quantity of domestic oil and gas reserves are known to be sufficient to meet this country's needs for well into the next century. What is lacking is the incentive to develop the production techniques. Only the ultimate maximization of domestic energy production, with equitable taxation, which allow for reasonable profits, will provide the required incentive for the nation's independent oilmen to continue discovering those petroleum reserves.

As shown in Exhibit 1 the growth of total lease revenues has historically been paralleled by the growth in total expenditures; so that despite a $79.1 billion increase in lease revenues since 1976 the excess of revenues over total expenditures has increased only $3 billion, just 4% of the marginal revenue increase. As a percent of lease revenues, the excess of revenues over expenditures has decreased from 23.18% in 1976 to 9.08% in 1981. This leads one to the conclusion that oil production is less profitable now than in 1976. The increase in revenue has been offset by increased costs of exploration and development and the new Windfall profit tax. The rate of return on fixed assets, another measure of industry profitability and vitality, has decreased from 13.23% in 1976 to 5.56% in 1981. This rate of return is simply not sufficient to encourage continued development of oil and gas production.[1] The oil production industry is clearly earning less net income than it did five years ago.

While the increase in income is entirely due to an increase in the price received for a barrel of crude oil (because as indicated in Exhibit 1, the annual barrels produced has actually decreased since 1979), the increase in expense is due to many cost factors - mineral interests, drilling, equipment and taxes.

The energy producing industry does not have the luxury of continued utilization of old equipment; rather, new equipment must be added each time a well is successfully completed, causing the book value of fixed assets to increase 117% in the five year period ending in 1981. Included in this increase is the cost of the acquired drilling rights from the mineral interest owner, usually the surface owner. The rights are for a specific term, usually three years, after which time another leasehold bonus must be paid if a producing well has not been completed. So once again the developer must compete with others, at the then current prevailing rate, in order to regain the drilling rights.

A drilling boom started in 1979 primarily, in my opinion, because of the deregulation of crude oil prices and the expectation of profits resulting from higher oil and gas prices. As shown on the graph in Exhibit 3 development costs increased from $20,378 million in 1978 to $55,689 million in 1980, or 173%. This demand for drilling sites, compressed into such a short time period, resulted in an extraordinary increase in the amount paid for leasehold bonuses, some going for as much as $1,000 per acre, (so that 120 acre drilling location would cost $120,000 in 1981 while the same location in 1978 may have been worth only $50 per acre or $6,000). So already the developer's investment has expanded many times over, before he has had an opportunity to explore for oil.

Another result of the immediate demand was seen in the construction and availability of drilling rigs. In 1979 there were approximately 2,200 drilling rigs in operation in the continental United States; in December 1981, there were a record 4,530 drilling rigs in operation; today there are about 5,644 rigs available for operation.

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[1] See Exhibit 2 for presentation and calculation of statistics.

Considering that it can take as long as twelve months to construct a rig, the demand for the 3,644 additional rigs occurred over a very short period of time. The result of the demand-push was a more than 100% increase in the cost of some drilling rigs; e.g., a rig capable of drilling to 10,000 feet cost approximately $2,500,000 in 1981, as opposed to $1,200,000 in 1978.

The rig rush of '81 has turned into the bankruptcy bust of '83 as the number of active drilling rigs has decreased to 1,860, less than the number in 1979, so that today only 35% of the available rig fleet is being utilized. This decrease in activity was primarily due to the fact that the cost of drilling had grown disproportionately to the financial benefits. In 1981, 6,974 successful exploratory oil wells were drilled with an average cost of $501,000 as compared with an average cost of $361,000 in 1980. This means that for a well to economically break even it must have at least 50,000 barrels of recoverable reserves, assuming a $30 per barrel sales price less an approximate $18 per barrel severance tax, excise tax and production costs; this is significantly above the realistic reserve expectation of the average exploratory well. Because many of the new rig purchases were financed with conventional lenders, the driller-developer found himself in a four-way squeeze - an increase in cost, a decrease in sales price, a decrease in investor participation, and debt servicing requirements. Thus many have gone out of business and many others have significantly curtailed their exploration budget, after restructuring their indebtedness. But even the debt restructuring process has become more difficult as banks will now lend at only 50% of the developed reserves computed at a currently more realistic sales price of $25-$30 per barrel, rather than 65% of developed and undeveloped reserves at $35-$40 per barrel. Rig owners are facing similar problems as the fair market value of their equipment, in a depressed industry with only a 35% utilization rate, has plumeted to a level which will not support the original loan. Because the owner-debtor has not been able to reduce the loan principal, the interest expense adds to the debt servicing pressures.

Adding to the cash-flow problem has been the unexpected decrease in the price of crude oil - from a high of $41 per barrel a short twelve months ago, to $28 per barrel today. The energy producing companies paid the high price for exploration and development anticipating a continually escalating price for their product. Instead the price has fallen 32% and future prices are predictably even less. Because the increase in income was primarily due to an increase in the price, rather than the production, this decrease has been financially catastrophic!

Because of the conflicting increase in cost accompanied by a decrease in revenue many individual investors, once the financial source of exploration funds, are no longer investing in the industry. Thus a large amount of funds for partnership participation (which does not require the same debt service repayments as conventional indebtedness) is no longer available.

One very important by-product of the decrease in drilling activity has been the increase in unemployment. Each drilling rig in operation supports approximately 15 jobs directly and another 45 jobs indirectly. Thus, the present 2,670 drop in active rigs has already added over 160,000 people to the unemployment rolls of this country.

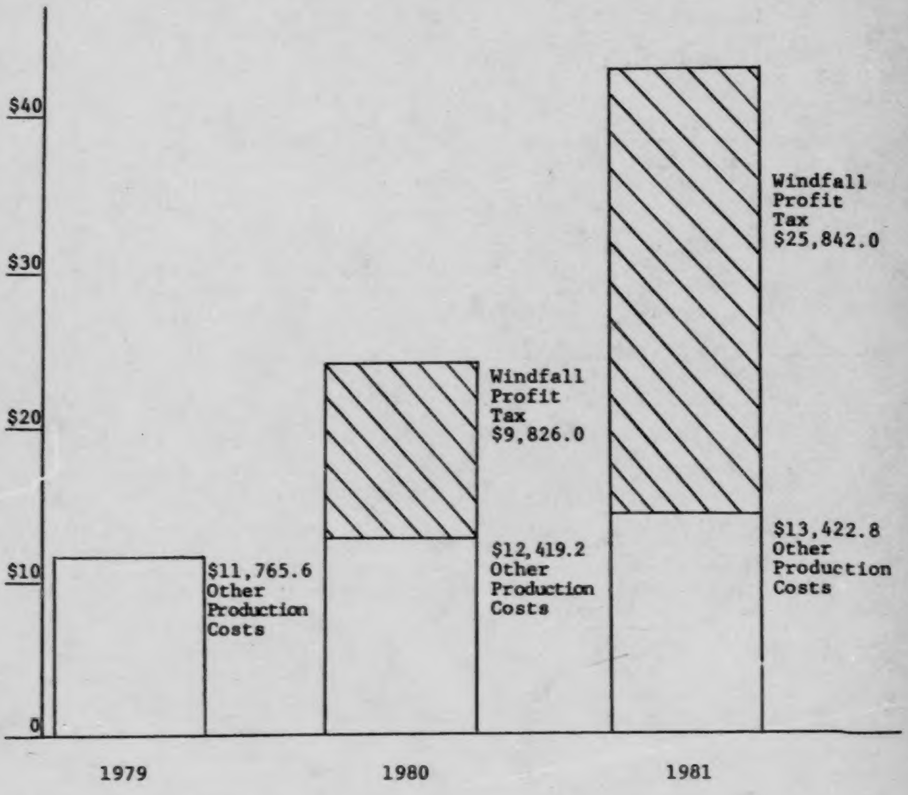
The costs of exploration and development have risen constantly since 1976. It is interesting to note (See Exhibit 3) that prior to 1980, aggregate development costs had always exceeded aggregate exploration costs. This is because there were still many developmental sites to be completed while oil was selling at lower controlled prices. But once the price was decontrolled production from these developmental sites became profitable and they were completed, since then the rate of continued developmental activity has flattened out. Therefore, the drilling expenditures of an exploratory nature (known to have a higher element of risk) have risen above the development costs for 1980 and 1981. Exploratory wells are by nature risky and are not as likely to be completed as producing wells. Hence the number of unsuccessful exploratory drilling venture (hereinafter referred to as a dry hole) can be expected to increase proportionately as the following table indicates:

| | Exploratory | | | Developmental | | |
|---|---|---|---|---|---|---|
| Year | Total Wells Drilled | Dry Holes | % of Total | Total Wells Drilled | Dry Holes | % of Total |
| 1981 | 23,764 | 12,769 | 54% | 24,939 | 6,358 | 26% |
| 1980 | 11,239 | 6,292 | 56% | 20,884 | 2,976 | 14% |

The average cost of an exploratory dry hole has increased from $408,000 in 1979, to $517,000 in 1980, to $656,000 in 1981. This 60% increase has made the industry reluctant to continue the exploration programs. Consequently, the number of wells drilled has predictably decreased in 1982 and 1983.

On Exhibit 4, you will find the growth of total exploration and development costs charted. You will find a graph of oil and gas production in million barrels for the same time period. Please note that the general trend (except for 1979 and 1981) has been for production in barrels to be directly related to the amount invested in exploration and development. Many factors affected 1979 production decrease including the anticipation of deregulation and the expectation of higher prices in future years. However, the relationship between total drilling costs and production is still apparent. With 1976 as a base year the production has increased 40.8, 204.0, 107.9, 147.6, 94.1 in 1977, 1978, 1979, 1980 and 1981 respectively for a total of 594.4 million barrels. During this time an aggregate $181.3 billion was spent for exploration and development costs; so that each dollar spent increased production by an average .3 barrels during that time.

Another squeeze for funds, and here is where we get to the real thrust of the point I wish to make, is the windfall profit tax. This alone has more than tripled the production cost in 1981, as shown in the following graph (production costs shown in million dollars):



The source of these total production cost figures is "Current Industrial Reports Annual Survey of Oil and Gas, 1981." Total windfall profit tax for calendar years 1980 and 1981 is determined by the Treasury Department Office of Tax Analysis. The 1981 windfall profit tax (approximately $10.58 per barrel of oil produced) has not added to the domestic reserves or increased domestic production. Conversely, estimates indicate that there is a 1:4 ratio between exploration expenditures and lease revenues, i.e., for each $4 of taxation, exploration is reduced by $1.[1] So for the $35.6 billion of total windfall profit taxes in 1980 and 1981 the exploration budgets have been shortened by almost $9 billion. The fact of the matter is that funds expended in exploration provide jobs and ultimately add to domestic reserves - funds paid in taxation do not!

In light of the aforementioned background, the question becomes, "What would be the effect of new tax legislation requiring the capitalization and 5 to 10 year amortization of successful exploratory and development costs?"

Initially, for the first 3-5 years until the pool of amortizable drilling costs had been accumulated - the drilling budgets would be reduced by approximately one-half the amount necessary to provide the funds to pay the incremental tax increase. Thus restricting the growth of drilling programs and consequently the rate of growth in production would decrease or even worse the production may begin to fall below the immediately previous year's level as it did in 1979 and 1981.

In addition, there are many producers who could not financially survive the initial 3-5 year period. These independent producers unable to attract venture capital and incapable of meeting bank loan requirements, would ultimately have to discontinue drilling activities adding significantly to the future production decreases.

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It has long been said that the major oil companies produce the oil, but the independent producers find it. By defining the major oil companies as the fifty largest producers, the following table documents this axiom:

Current Industrial Reports - Annual Survey of Oil and Gas 1981
Comparison of Drilling Activity

| | | NUMBER OF WELLS DRILLED | | | |
|---|---|---|---|---|---|
| | | Largest 50 Companies | | All Other Companies | |
| | Total | Amount | % | Amount | % |
| All Wells | 68,622 | 17,097 | 24.9% | 51,525 | 75.1% |
| Exploration Oil and Gas Wells | 10,995 | 1,865 | 17.0% | 9,130 | 83.0% |
| Development Oil and Gas Wells | 38,500 | 12,036 | 31.3% | 26,464 | 68.7% |
| Dry Holes Oil and Gas | 19,127 | 3,196 | 16.7% | 15,931 | 83.3% |

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[1] Oil and Gas Journal, March 7, 1983, Vol. 81, No. 10, "U. S. Windfall Profit Tax seen falling $152 billion short of target," p. 27.

It should be emphasized that these other oil companies drilled 83% of the 6,974 successful exploratory oil wells which (as has been previously noted) had an average cost of $501,000 per well or a total drilling budget of $2.9 billion.

The independent oil companies have to drill a disproportionately larger percentage of the exploratory (rather than development) wells, because the exploratory fields are more readily available because the major oil companies generally avoid such "wildcat" risks. "Wildcat" wells are typically more expensive and result in less reserves. Once an oil field has been discovered, the optimum development is so expensive that the independent commonly may have to assign an interest to a major oil company in return for its financial resources to insure development. But, it all begins with the risky exploration process. Without the initial step, performed largely by independent producers, most of the incremental production since 1980 would not now be available.

While the independent oil companies do 83% of the exploratory drilling and 69% of the development drilling they have only 18% of the 3.1 billion barrels of crude sales, or 573 million barrels. Thus these independent producers do not have sufficient financial resources to withstand a long period of economic hardship or a permanent adverse tax effect, for example - a loss of the statutory depletion deduction.

The statutory depletion deduction (available only to independent producers) is scheduled to be reduced to 15% of wells gross income, limited to 50% of the wells net income, and further limited to 65% of the company's taxable income before depletion. There are no authoritative statistics available for the amount of statutory depletion, or the resulting tax effect applicable to independent producing companies. However, an estimate can be made in the following manner for 1981 when the statutory depletion rate was 20%:

| | | |
|---|---|---|
| Total lease oil and gas revenue | $ 108,492 | mil. |
| Less revenue for largest 50 companies | 88,373 | mil. |
| Balance - independent oil companies | 20,119 | mil. |
| 1981 depletion rate | 20% | |
| Maximum allowable depletion | 4,024 | mil. |
| Estimate effect of 50% and 65% limitation | 75% | |
| | 3,018 | mil. |
| 1981 Corporate tax rate | 46% | |
| Resulting tax savings of statutory depletion deduction | $ 1,388 | mil. |

If this deduction were to be eliminated, this tax savings would actually become a tax cost, and the funds would have to be provided by reducing the drilling budgets. Because production costs cannot be

it without adversely affecting production. Based upon an average
ost of $656,000 per exploratory well, this would result in 2,115
ess wells being drilled. Ultimately this would translate into a
izable and dangerous reduction in domestic production.

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In 1981 the independent oil and gas producers (exclusive of
ne largest fifty) accounted for 18.4% of all the domestic crude
roduction. Contrast this with the fact that independents also
ccounted for 41.6% of all of the production from stripper wells.
tripper wells as defined by the U. S. Department of Energy are those
ells producing less than ten barrels per day during any twelve month
eriod. Over 14% of the 1981 total domestic production came from
hese stripper wells (438.9 million barrels). The major oil producing
mpanies have disproportionately less stripper well production be-
use, as previously noted, they tend to develop known oil fields and
w stripper production usually results from exploratory drilling,
ecause a field yielding only stripper production would not normally
developed further. The cost of operations for major oil companies
ncludes a large portion of fixed cost per well; so that their rela-
ive cost of operating a stripper with little production is similar
their cost of operating a well producing multiples of ten barrels
r day. Hence they cannot profitably operate a stripper well and
ey will either sell it or operate it for a short time, before ter-
nating its operation.

The rate of stripper production closely parallels the rate of
tal domestic production (see Exhibit 5). An exception to this is
idenced by the rate of ascent and descent being sharper. Since
78, the trend has been for stripper production to decrease. The
81 increase is directly related to the effect of the renewed dril-
ng activity in 1980 and 1981. Without the new drilling program,
e line of descent probably would have continued at roughly the same
te. Because a stripper well produces less than ten barrels per day,
e net income from a stripper well (after excise and severance taxes)
es not contribute to the fixed production expenses in direct propor-
on to its respective overhead burden. This is to say a stripper well
not always a profitable well. The sharp decrease in production in
79 and 1980 can be directly related to the anticipation and eventual
actment of the windfall profit tax.

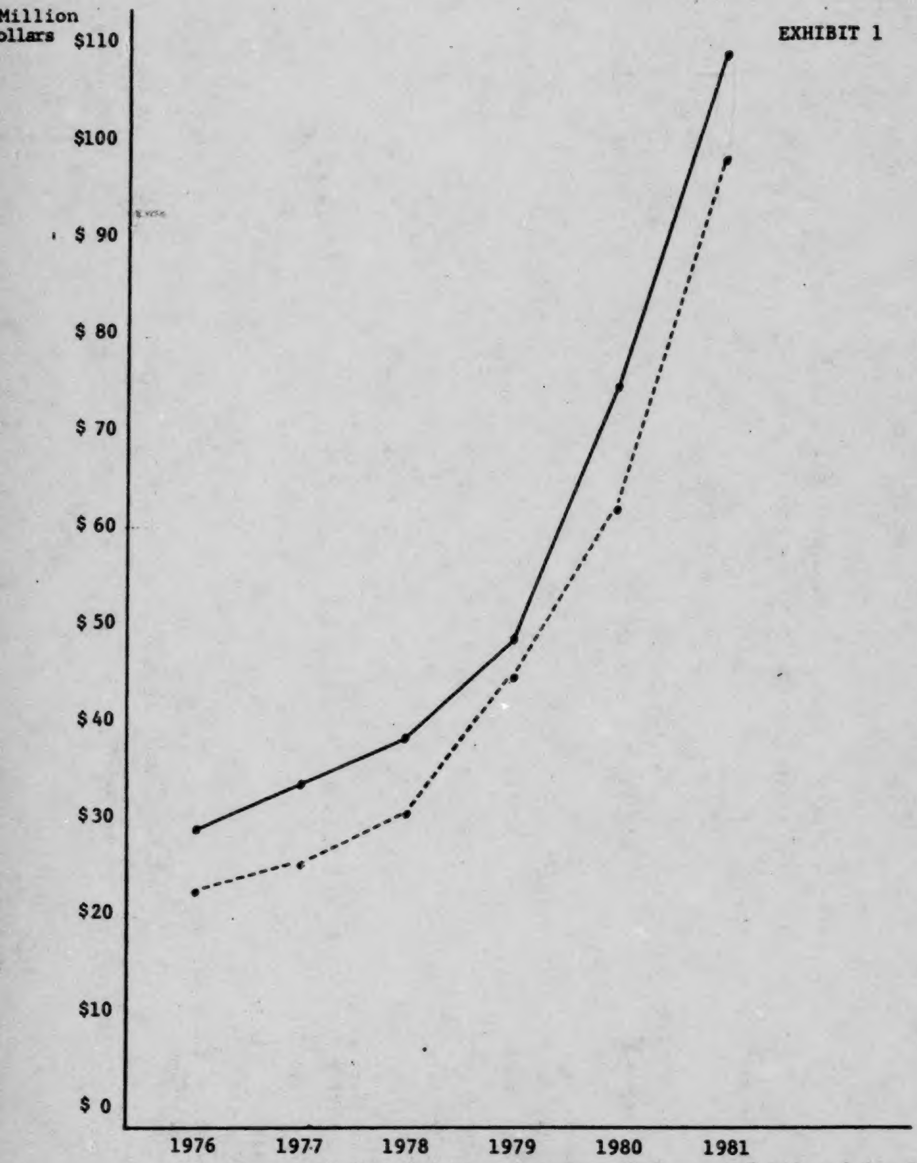
With the considered increase in the windfall profit tax on
ripper production these wells which were marginally producing only
to 5 barrels per day were no longer profitable. Consequently they
re shut-in. Should the independent producers windfall profit tax
te on stripper well production be increased, even those wells pro-
cing as much as 5 to 10 barrels per day would also be shut-in. The
sult of this would be that the rate of domestic stripper production
uld decline rapidly and sharply. The end result would be an eventual
crease in both windfall profit tax and income tax, revenues accrued
the Federal Treasury as currently producing stripper wells are
ut-in and future discoveries of marginal production would not be
mpleted.

In summary, I submit that any legislation adversely impacting the independent producers: (a) drilling cost write-off; (b) statutory depletion deduction; and/or (c) windfall profit tax rates would have a correspondingly adverse impact on the domestic energy production. A continued decrease in domestic energy production, comparable to the 1978 through 1981 rate, would prevent this country from becoming energy independent. The consequential negative effect upon trade deficits, employment and many other economic factors would be severe indeed.

This subcommittee is charged with the specific task of oversight of energy taxation. But on a much larger scale, you are responsible for striking a balance between federal budget requirements and the profit incentive necessary to develop domestic energy production levels sufficient to achieve and maintain our independence from unreliable foreign energy sources. Without energy independence, our future national security is uncertain.

The first, last and foremost consideration of this subcommittee should, and no doubt will be, the human effect(s)/consequences of the proposals and/or recommendations which it makes as a result of these hearings. This human effect which is, in essence, the effect that this subcommittee's actions might ultimately have on people in New York City, Tampa, Jersey City, Knoxville and Bakersfield, as well as those throughout the nation, is one that must be considered also when any new tax legislation is proposed. Additional taxes levied upon independent producers would take funds out of the borrowing, employing, exploring, developing, producing and repaying cycle. At some point, given current economic conditions, new taxes (which remove additional funds from this cycle) would inevitably lead to the financial collapse of the independent oil producing industry as well as the almost one million people it employs.

EXHIBIT 1



Source: Current Industrial Reports - Annual Survey of Oil and Gas 1981
U. S. Department of Commerce Bureau of the Census
Lease revenues ————
Total expenditures ----------

Exhibit 2

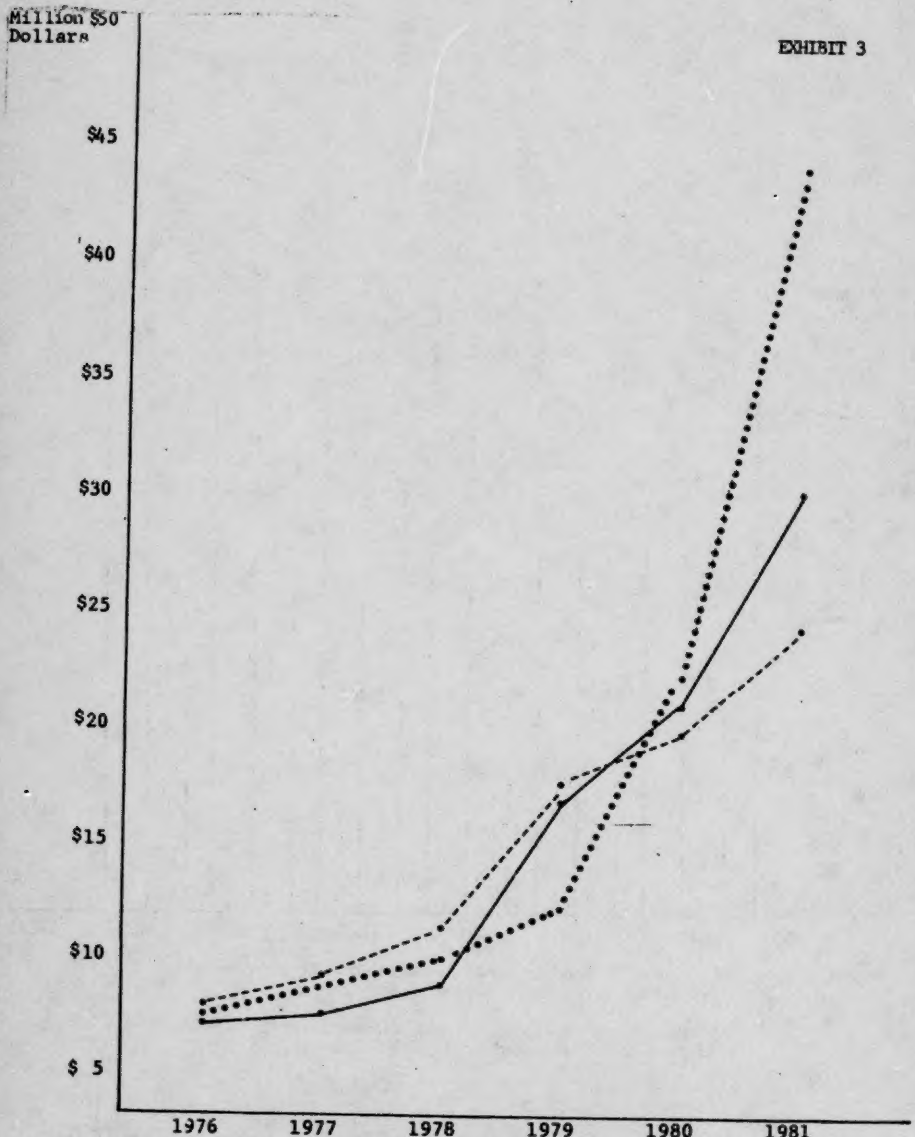
## CURRENT INDUSTRIAL REPORTS - ANNUAL SURVEY OF OIL AND GAS 1981

## SUMMARY OF DETAILED NET COMPANY INTEREST STATISTICS

Stated in millions of dollars

| | 1981 | 1980 | 1979 | 1978 | 1977 | 1976 |
|---|---|---|---|---|---|---|
| Mil. Bbls. produced | 2,441.7 | 2,495.2 | 2,455.5 | 2,551.6 | 2,388.4 | 2,347.6 |
| Lease revenues | $ 108,492.2 | $ 74,903.0 | $ 48,430.8 | $ 38,279.7 | $ 33,955.6 | $ 29,366.8 |
| Expenditures (Capitalized and expensed): | | | | | | |
| Exploration | 30,674.2 | 20,830.8 | 15,617.2 | 9,367.9 | 7,794.9 | 7,183.9 |
| Development | 25,015.7 | 19,578.9 | 17,303.6 | 11,010.7 | 9,212.9 | 7,734.8 |
| Production | 42,945.8 | 22,245.2 | 11,765.6 | 9,994.6 | 8,717.4 | 7,639.9 |
| Total | 98,635.7 | 62,654.9 | 44,686.4 | 30,373.2 | 25,725.2 | 22,558.6 |
| Excess revenues over expenditures | $ 9,856.5 | $ 12,248.1 | $ 3,744.4 | $ 7,906.5 | $ 8,230.4 | $ 6,808.2 |
| % of revenues | 9.08% | 16.35% | 7.73% | 20.65% | 24.24% | 23.18% |
| Average gross book value of fixed assets: | | | | | | |
| (One-half of total beginning of year and end of year values) | $ 177,238.3 | $142,316.0 | $117,200.5 | $100,040.6 | $ 89,149.8 | $ 81,758.5 |
| Rate of Return on fixed assets | 5.56% | 8.61% | 3.19% | 7.90% | 9.23% | 13.94% |

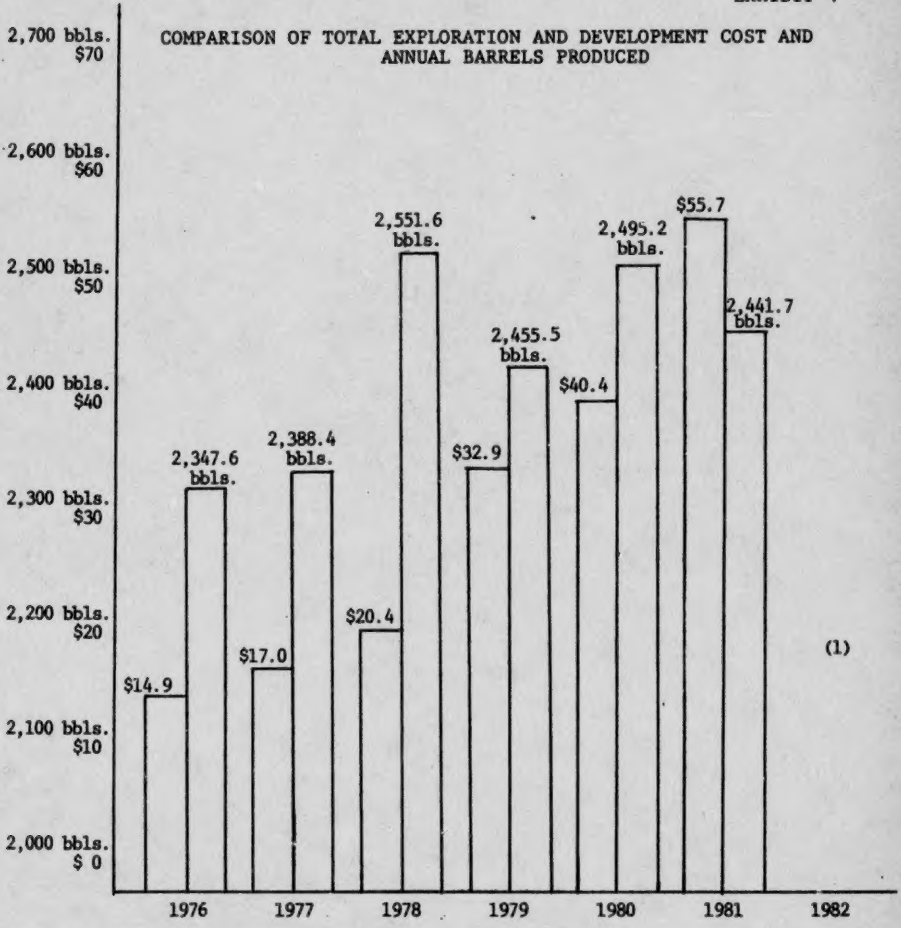
EXHIBIT 3



Source: Current Industrial Reports - Annual Survey of Oil and Gas 1981
U. S. Department of Commerce Bureau of the Census
Exploration Costs———; Development Costs-------Production Costs••••••••

EXHIBIT 4

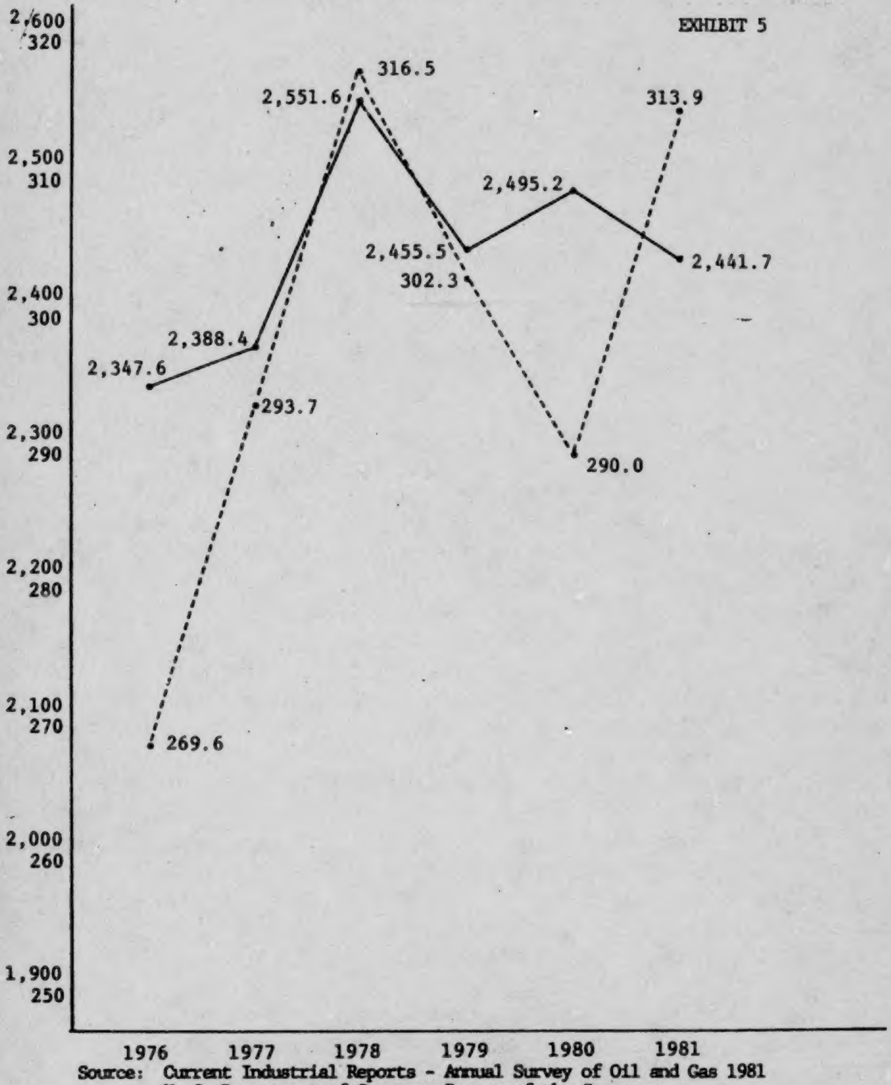
## COMPARISON OF TOTAL EXPLORATION AND DEVELOPMENT COST AND ANNUAL BARRELS PRODUCED



Source: Current Industrial Reports - Annual Survey of Oil and Gas 1981
U. S. Department of Commerce Bureau of the Census

(1) Exploration and development costs not available for 1982.
1982 production estimated at 3,165 million barrels.

EXHIBIT 5



Source: Current Industrial Reports - Annual Survey of Oil and Gas 1981
U. S. Department of Commerce Bureau of the Census
Crude Petroleum and Condensate Production 1,900 to 2,600 mil. bbl.————
Stripper well production 250 to 320 mil. bbl. scale--------

## STATEMENT OF WALTER W. BRUDNO, COUNSEL, REPRESENTING DEMINEX U.S. OIL CO., TEXASGULF, INC., AND ELF AQUITAINE, INC.

Mr. Brudno. I am Walter Brudno, an attorney with the law firm of Kilgore & Kilgore in Dallas, Tex. The firm has been engaged in representing members of the oil industry for approximately 50 years.

I am primarily concentrated in the field of taxation of domestic and international operations in which I have been engaged for about 40 years.

I am here on behalf of three producing companies, all domestic companies, which are wholly owned by foreign shareholders.

The first is Deminex U.S. Oil Co., which is essentially the same company as a former Texas company which qualified as an independent producer. Its shares are now owned by a German company.

Texasgulf, Inc. was also an independent producer. Its shares are now owned by a French company, as are the shares of ELF Aquitaine, Inc., which was recently formed.

Each of these three domestic companies is now denied independent producer status because its shares are held by a foreign company which is engaged in refining or shares of which were held by a company so engaged.

I propose to demonstrate to this subcommittee that treatment of these three domestic producers and any others similarly situated as though they were integrated oil companies is contrary to our national energy interests and contrary to the intent of Congress due to—entirely—to legislative oversight.

First, I would like to summarize my views on the differential treatment which is the subject of this committee's examinations.

In 1975, Senator Cranston stated that he proposed the special treatment of independents in recognition of the major role that they played in the discovery of new reserves, noting that they drill 85 percent of the new fields and new finds, and I would like to point out that independents continue on that course.

During 1982, only about 20 percent of all domestic drilling was exploratory and about 11½ percent of all drilling was carried out by the major integrated oil companies which preferred to concentrate predominantly in the drilling of development wells. Development wells serve only to deplete known reserves and do nothing to increase available reserves.

Last year 60 percent of the drilling expenditures by the two French-owned companies I represent were for exploration. Fifty-one percent of the expenditures by the German-owned companies were also for exploration and it is projected that 68 percent of the expenditures for 1986 will be for exploration.

These companies concentrate on exploratory drilling, notwithstanding the fact that 80 percent of development wells and only about 8 percent of exploratory wells are producers.

The risks of these wildcatters are substantially greater than those of the more conservative majors as demonstrated by the fact in 1982 only 7.2 percent of wells drilled by the majors were dry holes whereas 92.8 percent of those drilled by others were dry.

The average number of drilling rigs operating in the United States, as you have been told, has declined from 4,521 to 1,846 in just 28 months. That is a decline of over 59 percent. Meanwhile, hundreds of independent producers and drilling operators have either been forced into bankruptcy or otherwise discontinued operations. Surely this decline in drilling activity and the number of risk-takers will materially diminish the discovery of new reserves and nothing should be done to further discourage the risk-taking involved in exploration.

I would like to turn briefly to the legislative oversight which I would like to call to your attention.

The 1975 Revenue Act intended to distinguish between companies engaged solely in production and those also engaged in refining or retailing. Through legislative oversight, acknowledged by Congress, the act inadvertantly treated as integrated companies those which are functionally independents, but have a related party which conducts foreign retailing or refining totally isolated from the domestic production and having no impact whatsoever upon the United States. At the behest of Belco Petroleum Corp., this oversight was partially corrected by a 1976 amendment. Belco had been excluded from independent treatment because it had a foreign subsidiary operating a chain of foreign retailing operation which sold only the product of foreign refineries.

The 1976 act attempted to correct this oversight by permitting a producer or related party to be engaged in foreign retailing without forfeiting independent status provided none of the domestic production was exported. Although both retailing and refining were treated alike in the 1975 act, the 1976 amendment addressed itself only to foreign retailing. Consequently, foreign refining continues to deprive producers of independent status although their domestic production and their foreign refining operations are in no way interrelated.

I know this subcommittee is more concerned with the larger issues of whether favored tax treatment of independents should be continued then with the narrower interests of the few companies which are denied that treatment solely because of legislative oversight. However, if the distinction between independent and integrated producers is to be continued, as I think it should be, I urge that this oversight be corrected.

A draft amendment which would do so has been annexed to the more detailed statement which I have furnished to the subcommittee. The amendment would isolate domestic production and foreign refining just as the 1976 act isolated domestic production and foreign retailing so that functional integration will be excluded from the tax benefits and functional independent production will be included in a manner which is consistent with the original intent of Congress.

I would like to note to the subcommittee that I have been here for two days and I have heard most of the testimony. Not a single representative of any major oil company has appeared. Normally one would expect when you are discussing the desirability of discriminatory legislation that those who would be crying the loudest would be those discriminated against. We can only conclude from that, I think, that this form of discrimination in no manner adversely affects the operations of the integrated oil companies.

Thank you for your attention, Mr. Anthony.

[The prepared statement follows:]

# STATEMENT BY WALTER W. BRUDNO ON BEHALF OF DEMINEX U.S. OIL COMPANY, TEXASGULF, INC., AND ELF AQUITAINE, INC.

*The law firm of Kilgore & Kilgore, Inc., at 1800 InterFirst One Building, Dallas, Texas 75202, prepared this statement. Kilgore & Kilgore, Inc., is registered under the Foreign Agents Registration Act of 1938, as amended, with the Department of Justice, Washington, D.C., as an agent of two foreign principals. These two foreign principals, and their addresses, are: Deminex U.S. Oil Company, Suite 840, Lock Box 340, Plaza of the Americas, North Tower, Dallas, Texas 75201; and Texasgulf, Inc., High Ridge Road, Stamford, Connecticut 06904. As required by the Foreign Agents Registration Act of 1938, as amended, the Registration Statement of Kilgore & Kilgore, Inc., is available for inspection at, and copies of this statement are being filed with, the Department of Justice. The registration of agents of foreign principals required by the Foreign Agents Registration Act of 1938, as amended, does not indicate approval by the United States Government of the contents of their political propaganda.*

The purpose of this statement is to call to the attention of the Subcommittee an unwarranted discrimination in the tax treatment of certain domestic oil and gas producers which resulted from legislative oversight and which is contrary to the national interests. In addition, the operations of these producers demonstrate the desirability of continued differentiation between the tax treatment of integrated oil companies and independent producers.

Deminex U.S. Oil Company ("DUSOCO") is a wholly-owned subsidiary of Deutsche Erdoelversorgungsgesellschaft mbH ("Deminex Germany"), a company organized in the Federal Republic of Germany. Texasgulf, Inc., and Elf Aquitaine, Inc. ("TG/EA") are wholly-owned domestic subsidiaries of Societe Nationale Elf Aquitaine ("SNEA"), a French company. For several years subsequent to enactment of Section 613A of the Internal Revenue Code, DUSOCO and Texasgulf, Inc., were independent producers as defined therein.[1] Each of these companies is engaged solely in oil and gas exploration, development and production and none of their production is exported.

A shareholder of Deminex Germany is engaged in refining foreign produced crude oil outside the United States, none of which is exported to the United States. SNEA refines foreign produced crude oil outside the United States, none of which is exported to the United States. As the result of the refining activities of these foreign shareholders, DUSOCO and Texasgulf, Inc., lost their independent producer status solely as the result of acquisition of their shares by the foreign companies. Elf Aquitaine, Inc., has been denied that status since its inception because of ownership of its shares by its French parent. These results are due to legislative oversight and are contrary to the policy reasons which motivated special treatment of independent producers, the justification for which is evidenced by the contribution being made by these companies toward fulfillment of the national energy objectives.

1. Reasons for Independent Producer Treatment. Congress has accorded special treatment to independent producers for two reasons: First, independent producers were recognized as a major factor behind the discovery of additional United States reserves of oil and gas.[2] Second, independent producers were hoped to provide strong competition to the major oil and gas companies in the areas of exploration and production of hydrocarbons.[3] Special tax benefits to independent producers were viewed as a strengthening of the position of such producers and thus as an instrument of national energy and economic policy.

In introducing his amendment to the 1975 Tax Reduction Act to provide special treatment of independent producers, Senator Cranston stated:

> "Overall, the independents drill 85 percent of the new fields and new finds. The wildcatting is essential to our finding the new wells we need in our energy shortage, and, in a period when we want to develop greater production, the majors do very little of that sort of risk endeavor in wildcatting."

Although there is no current energy shortage the chaotic condition of the international oil economy, as well as the adverse effects of oil imports upon the balance of payments, make it imperative that the United States reduce its dependence upon oil imports by increasing its available domestic reserves. This can be accomplished only by exploratory drilling.

During 1982 only about 20 percent of all domestic drilling was exploratory and only 11.5 percent of all drilling was carried out by the major integrated oil companies and 88.5 percent by others.[4] The majors concentrated predominantly in the drilling of development wells which serve only to deplete known reserves and do nothing to increase available reserves. By contrast, 60 percent of the drilling expenditures by TG/EA, functionally an independent producer, were for exploration and 40 percent for development. Similarly, 51 percent of the drilling operations of DUSOCO were for exploration and 49 percent for development. The company has projected that 68 percent of its drilling expenditures through 1986 will be for exploration and 32 percent for development. This, notwithstanding the fact that approximately 80 percent of development wells are producers while only about 8 percent of exploratory wells are producers. In 1982, only 7.2 percent of the wells drilled by the major integrated companies were dry holes, whereas 92.8 percent of wells drilled by others were dry. Thus, it is demonstrated that the high risks of exploratory drilling are largely undertaken by independent producers and are avoided by the large integrated companies in favor of exploiting their existing reserves.

In December, 1981, the average number of drilling rigs operating in the United States was 4,521. This declined to 2,696 rigs in December, 1982, and to 1,846 rigs in April, 1983--a total decline of over 59 percent. Meanwhile, hundreds of independent producers and drilling operators have been forced into bankruptcy or have otherwise discontinued operations. This decline in drilling activity and in the number of risk takers in the industry cannot but have a serious adverse effect upon exploration and the discovery of new reserves.

2. The Independent Producer Under the 1975 Act. Congress wished to deny independent producer status to integrated oil companies. With this in mind, the definition of independent producer in 613A focused on excluding taxpayers with refining or retailing operations. The general idea of such a definition of course was sound: an integrated oil company was one that sold its production of crude oil to a refining division, which in turn would sell its refined products to a retailing division for ultimate distribution to the consuming public. The drafters of the independent

producer definition were not able, due to the constraints of time, to turn this general aim into a technically sound definition for tax law. As Mr. Laurence Woodworth, chief of staff for the Joint Committee on Internal Revenue Taxation, testified during the course of Senate hearings on the first round of technical amendments to the 1975 Tax Reduction Act (in response to Senator Long's comment that the independent producer definition was drafted on short notice):

> "I believe it had to be available within a day or two of the time I was asked to prepare the draft. Also, there was not any opportunity for the usual staff review of this particular provision.
>
> "In any event, it contained a number of problems which we have heard about since that time. In the ordinary course of events, these would have been the kinds of problems which would have been brought out in hearings by those testifying before the Finance Committee.
>
> "There was no opportunity for that type of consideration of technical problems . . . ."[5]

Recognizing that some integrated oil companies would have separately incorporated their various producing, refining and retailing divisions, the drafters of the independent producer definition included the concept of a "related person." Related persons were to be treated as one taxpayer, for purposes of the independent producer definition. One effect of the definition of "related person" was to cause an independent producer to lose that status if a related person conducted any foreign retailing or refining operations, even though the related person used no United States production in its operations.

3. Partial Curing by the 1976 Act of the Technical Problems of the Original Independent Producer Definition. The Tax Reform Act of 1976 cured a number of the technical problems in the quickly-drafted definition of independent producer. As the Senate Finance Committee wrote in its report to the full Senate:

> "Certain provisions of the Tax Reduction Act of 1975 relating to percentage depletion have been or may be interpreted in a manner which is inconsistent with what

> the Committee believes to be the intent of Congress in enacting that legislation. In some cases, the literal language of the statute requires unintended results. In other cases, the statutory language is ambiguous."[6]

One of these technical amendments was concerned with the unintended impact of the original independent producer definition upon taxpayers with isolated foreign retailing operations but no parallel amendment was made to eliminate the unintended impact of that definition upon taxpayers with isolated foreign refining operations carried on either by themselves or by a related party.

4. Independent Producers with Foreign Retail Operations. The 1976 Tax Reform Act amended the definition of independent producer to include taxpayers who otherwise would be independent producers but for retail sales made outside the United States either directly or through a related party, if no domestic production of the taxpayer was exported during the taxable year or the immediately preceding taxable year. This amendment was made at the request of Belco Petroleum Corporation. Belco was an independent company that produced oil and gas in the United States. None of this production was refined or marketed by Belco or a related company; all of Belco's domestic production was sold to independent companies for domestic use. In addition, a subsidiary of Belco owned a chain of gasoline stations in Israel. Although Belco was functionally an independent producer with regard to its domestic operations, it was excluded from independent producer treatment by the original definition of independent producer enacted in 1975 solely because of its subsidiary's independent foreign retail sales. The Ford Administration supported the Belco amendment, saying that, "The thrust of the amendment is consistent with the original intent of the retailer and refiner roles and may be viewed as correcting a legislative oversight." (emphasis added; note linking of retailing and refining concepts)[7]

5. Proposed Corrective Action. Although the concepts of retailing and refining were to act in tandem as a definition of an independent producer, the 1976 Act only amended the retailer half of the definition. It is recognized that this Subcommittee will be more concerned with the larger issue of whether favored tax treatment of independent producers should be continued, than with the narrower interests of the

companies I represent. However, if such treatment is to be continued, as we submit it should be, it is urged that the legislative oversight of previous Congresses should be corrected. We propose that an adjustment be made to the refiner half of the independent producer definition parallel to that which was made to the retailer half of the definition. It is proposed that it be made clear that foreign refining of non-United States production by a company related to a United States producer will not deny independent producer status to a domestic producer with no domestic retailing or refining operations (either by itself or by a related company). A draft of an amendment which would achieve this result is attached as Exhibit A.

The foreign refining operations that deny independent producer status to DUSOCO are even more remote than were the retailing operations of Belco's subsidiary. In the case of Belco, the retailing operations were conducted by the taxpayer's own subsidiary, although on a completely separate basis from Belco's exploration and production activities in the United States. DUSOCO, on the other hand, has no refining operations of its own either in the United States or abroad. DUSOCO fails to meet the definition of independent producer, as that definition is presently written, because foreign shareholders of its shareholder have refining operations conducted outside of this country. All of DUSOCO's production is sold in the United States to unrelated companies so that none of it is used by its related foreign companies.

The refining operations associated with TG/EA are equally remote. These companies have no refining operations in the United States or abroad, nor does either of them have any subsidiary engaged in refining operations. As is the case with DUSOCO, they fail to meet the present definition of an independent producer because a foreign related person conducts refining operations outside of the United States using non-U.S. crude oil.

6. Conclusions. To withdraw the benefits of independent producer status at a time when the independents are struggling for survival, drilling operators are declining in number and drilling activity is at a low ebb, as demonstrated by the decline in drilling rigs in operation, would accelerate a trend which is in the national interest to reverse. Not only does domestic exploratory drilling increase our domestic

reserves but it also has a significant "ripple" effect in employment of drilling crews, utilization of geological and geophysical services, and purchases of pipe, casing, drilling mud and other equipment, supplies and services. All of these activities naturally produce taxable income to the recipients which offset in some substantial measure the revenue costs of according special treatment to independent producers.

In the case of the companies for whom I speak, they are responsible for sizable movements of foreign capital into domestic operations. Certainly it is desirable that foreign funds be encouraged to explore for domestic reserves. To the extent that their funding of exploration is from foreign sources there will be a direct benefit to our balance of payments as well as a contribution to our domestic economy. To the extent funding is out of domestic capital and earnings there would be like benefits to our economy. The results of any successful exploratory efforts would accrue entirely to the domestic economy through an increase in reserves and domestic production, none of which can be exported under existing law.

It is characteristic of the industry that the major portion of its profits from successful efforts, after Federal and State Income, Excise, Severance and Property Taxes, is committed to further exploratory effort and to the substantial cost of development of discovered reserves. It has been characteristic of the major integrated companies with foreign operations that their profits therefrom are rarely repatriated to the United States and it may be expected that the foreign companies would be even less likely to repatriate their domestic earnings in view of the fact that their major incentive for investment here is the great political stability, the favorable economic environment and the freedom from exchange controls in the United States.

From the foregoing it is clear that preservation of the current tax treatment of independent producers is in the national interest. It is both equitable and desirable that like treatment be accorded to domestic producers who are now denied such treatment solely because foreign shareholders, or shareholders of shareholders, are engaged in refining abroad. Such treatment should be extended to such domestic producers only where the refined product is not imported into the United States and domestic production is not exported from the United States, as is provided for in the proposed amendment. By thus isolating domestic production and foreign refining functional integration would be excluded from and functional independent production would be included in the independent producer definition.

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## FOOTNOTES

[1] DUSOCO is successor by technical merger to Creslenn Oil Company, a closely-held Texas corporation, and continues the operations of that company substantially as before the acquisition, but on a larger scale due to injection of additional capital by its foreign owner. Elf Aquitaine, Inc., did not exist prior to its formation in early 1982.

[2] Senator Cranston, speaking on the floor of the Senate on March 20, 1975. Congressional Record, 94th Congress, 1st Session, Volume 121, Part 33, Page 7775.

[3] Ibid.

[4] The complete yearly review of U.S. oil and gas activity, Petroleum Information Corporation, Denver, Colorado.

[5] Testimony of Laurence N. Woodworth, chief of staff, Joint Committee on Internal Revenue Taxation. Certain Committee Amendments to H.R. 10612, Hearings Before the Committee on Finance, United States Senate, 74th Congress, 2d Session, July 20, 21, and 22; Oral Testimony of July 22, 1976, with Written Testimony. Government Document Y4.F49: Am 31 Part 2, Pages 649-652.

[6] Senate Committee Report, 94th Congress, 2d Session, S. Rep. No. 94-938 (1976) 424.

[7] Administration Position, Page 337; in 94th Congress, 2d Session, Committee Print of United States Senate Committee on Finance, Tax Reform Act of 1976, H.R. 10612, Testimony to be Received Tuesday, July 20, 1976, and Administration Position on Certain Provisions of H.R. 10612. Government Document Y4.F49: T19/49/976-2.

## EXHIBIT "A"

## PROPOSED AMENDMENT
## TO
## SECTION 613A(d)(4) OF INTERNAL REVENUE CODE

SECTION_____. TECHNICAL CORRECTION TO DEFINITION OF REFINER.

(a) In General. -- Paragraph (4) of Subsection (d) of Section 613A of the Internal Revenue Code of 1954 (defining certain refiners excluded from treatment as Independent Producers) is amended by adding at the end thereof the following:

> "For purposes of this paragraph, refining of crude oil shall not include refining outside the United States, if no domestic production of the taxpayer or a related person is exported during the taxable year or the immediately preceding taxable year and the taxpayer establishes to the satisfaction of the Secretary that the retail value of products of crude oil refined outside the United States and exported to the United States by the taxpayer, or by a related person, during the taxable year does not exceed $5,000,000."

(b) Effective Date. -- The amendment made by this section shall be effective for all taxable years in respect of which assessment and collection of tax is not barred by Section 6501(a) of the Internal Revenue Code of 1954 or in respect of which credit or refund of overpayment of tax is not barred by Section 6511 of the Internal Revenue Code of 1954.

Mr. ANTHONY. I noticed the same thing.

I am glad you brought it up for the record rather than having me bring it up. The thought occurred to me yesterday about the end of the day, after hearing all of the witnesses and seeing who would be testifying today.

I guess I came to the same conclusion, being a lawyer by trade. That is the way we are taught to think. I just have one question for you representing your clients. What would they do differently if they were granted the exemption than what they are doing right now?

Mr. BRUDNO. As far as the French-owned companies are concerned, all of their shares are owned by ELF Aquitaine S.A., which is a French company of which 67 percent is owned by the French Government. They depend largely for their exploration budget on injections of capital from their French parent. Now, the French parent has operations in 33 foreign countries. They have to choose in which countries they are going to spend their exploration budgets. Obviously they will spend the exploration budget where their productivity is likely to be the highest, and their net after-tax proceeds are likely to be the greatest. This will undoubtedly have a material effect upon the amount of exploration money that is sent into the United States plus the fact that the more money, the larger portion of the budget which is available for exploration due to reduced taxation will obviously increase the amount of exploratory expenditures.

With respect to the German-owned company, Deminex, they are required to conduct their exploration almost entirely on locally generated profits. Obviously, again, to the extent that their profits are reduced their exploration budget is going to be reduced and their exploratory activity is going to be reduced.

Mr. ANTHONY. So I deduct from all of that that not only do you favor the retention of the special tax treatment for independent producers, but you think that it has served a useful purpose?

Mr. BRUDNO. I think it has definitely served a useful purpose. I wanted to point out that there has been a disparity of treatment until now between the foreign refining as tainting independent producer status and foreign retailing which does not. Yet conceptually there should be no difference.

Mr. ANTHONY. I think your testimony made it very clear as between the two. You provided the committee with some valuable testimony and evidence as to how a definition written in haste behind closed doors without detailed public hearings sometimes can leave others out in the cold.

Mr. BRUDNO. Exactly.

Mr. ANTHONY. That is exactly the reason the full committee chairman asked the oversight subcommittee to take a look at this very complicated tax policy because it is broad, not only in tax policy, but it is tied up in energy policy, and that also puts us into foreign and domestic policy.

So it does become very complicated. The fact is the law prior to 1975 did one thing and then through a series of amendments has been changed in piecemeal fashion. That was the challenge the full committee chairman gave this subcommittee. We were asked to hold 2 days of oversight hearings, to allow witnesses to come in and testify and to give the subcommittee evidence so that we could prepare a report for the full committee. Only then can we begin to deliberate whether or not the tax preferences are, in fact, good tax policy for the United States and helps produce a positive energy policy that balances foreign and domestic concerns..

You have certainly highlighted how we can drive foreign dollars into the United States to help us become more energy self-sufficient, albeit using someone else's dollars.

I must admit I kind of like that idea instead of seeing our dollars flowing in the opposite direction.

Mr. BRUDNO. If I may, I would like to add a footnote to my remarks.

I have done considerable study of this matter. I have concluded that this differential treatment that affects my clients is in direct contravention of the treaties of friendship, commerce, and navigation with France and Germany.

Mr. ANTHONY. In that case, you can take that to the administration and to the Secretary of State.

Mr. BRUDNO. I have the German and French foreign offices working on it, sir.

Mr. ANTHONY. Sorry about the interruption. I was being advised we have some lovely schoolchildren coming in to participate in their right as Americans to watch their Government in operation. They are certainly welcome. Since they are here, I think we may keep this hearing going a little bit longer.

I would hate for them to come in and have them watch the chairman bang the gavel.

Mr. WARD. Mr. Anthony, something occurs to me.

We were discussing the purchase of——

Mr. ANTHONY. I wasn't through with you anyway. You have a really nice statement in your testimony that I wanted to talk to you about. While I have it on my mind, let me get it out of the way.

On page 3 of 5, you have a paragraph in there I think really needs to be highlighted. I think it is beautiful. It says you frankly don't understand how the banking industry was considered incapable of supporting the expense and detail for administering a simple flat one percent tax rate while the oil industry is supposed to be able to handle all the costs, work and complications for a discriminatory tax based on three types of oil wherein the taxes for various entities to a single contract can vary from 0 to 25 to 30 to 50 to 60 to 70 percent.

Let me say to you if the bankers are successful in their efforts to repeal the withholding provisions, maybe you can send a letter to the President and ask him if he can crank up enough letters to Congress to assist you on windfall profit tax.

Maybe you could make a good partnership in a lobbying effort.

Mr. WARD. If we could ever get the royalty owners organized like they did their depositors.

The thing that occurs to me as an independent producer, what would happen if you took away the drilling intangibles or lowered the depletion further?

I quit. That is simple. I can't get any investors as it is now, so I know I am not going to get anyone who goes any lower.

One thing that occurs to me that I think is a Catch-22 situation for you in regard to the purchase of a stripper well properties from majors by independents, not only can you not transfer the depletion, but you get stuck with a 60-percent windfall profit tax rate because, when the independent purchases the stripper well, he can't go from 60 to 0 exemption.

So we can't change that because, if we change that, then you are going to have sweetheart deals wherein it changes the value of the property based upon what the tax rate is.

Am I clear there?

Mr. **Anthony**. Yes.

Any of the witnesses of the panel have a closing comment that you would like to make?

Mr. **Riley**. I would like to make one on the sources of investment capital for drilling ventures.

Since July 5 of last year when the Penn Square Bank failed, the conventional bank lenders have had a hands-off policy regarding oil and gas-producing loans. Up to that time you had been able to borrow perhaps 65 percent of the expected discovered reserves from that property. Since that time, they have lowered their loans, if they would make them, less than 40 percent of the known reserves from that property.

At the same time, if that producer is also a driller and has a drilling rig, he is seeing his rigs stacked for a period of time. A rig was sold in Oklahoma City last week that was 2 years old, originally cost $2.5 million, and had a market value at auction of $235,000. So we are seeing a significant drying up of conventional bank funds for investment in the drilling, exploration, and the equipment purchasing of this entire industry.

Mr. **Anthony**. Mr. Riley, do you think if the Congress reported out legislation that sought to repeal the tax preferences that it would compound that problem?

Mr. **Riley**. Yes, sir, I believe it would, because we have to encourage the investment from the individual sector. The person who typically has invested in oil and gas ventures before has to be encouraged and given the tax incentives to maintain them to continue that investment program. At this point, because of the risk involved, and because of the unknown future tax status, those individuals are not making investments in the industry.

Mr. **Anthony**. One final question for you, Mr. Riley.

Some have suggested eliminating the windfall profit tax in exchange for eliminating percentage depletion and immediate expensing of intangible drilling costs. I was wondering what your personal thought would be about that.

Mr. **Riley**. I don't know. I know most independents are most anxious to get rid of the windfall profit tax because it actually has added $25 billion to their total production costs, more than double the normal production costs.

If it is a trade-off of issues, I think we would have to look at those combinations of things and see what could be done. However, if the goal of the report of this committee is to maximize domestic production, I think you are looking at, instead of a trading off, you are looking at trying to provide incentives for continued exploration. And elimination of any of those tax benefits would not provide in my opinion that total domestic incentive that we are looking for.

Mr. Anthony. Before we close, I certainly would like to give the Members an opportunity to ask any additional questions. Further, if the staff has any additional questions, be sure and bring them to my attention.

Mr. Dwyer. I thought I would like to finish the last 30 seconds of my statement. It ends with a listing by the CIA of some 13 supply disruptions which have taken place since Mosadegh nationalized the Iranian oil companies. There have been an awful lot of minor wars there also, including people forgetting the Nigerian civil war caused a disruption. There has been a lot of pipelines blown up.

The whole story is that we depend for 30 percent of our domestic demand, on imports. Even at the present low level of demand imports are 30 percent. But we see very little prospect of our present level of domestic production going up very much.

A 5-percent increase in domestic demand would result in a 15-percent increase in imports, just like that.

I have noticed in the very first line of figures, showing that demand is beginning to go up, I just noticed for the first time in the last 3 weeks electric power production has gone up—it has been down for a very long time. And I think we could see a very substantial increase in oil imports.

As I said, I think the OPEC cartel will continue. And I think the $29 a barrel price is holding.

Consumers shouldn't complain. The value of the dollar has been declining. That represents a substantial reduction in the price of crude oil in constant dollars. However, that also means a substantial reduction in the return to domestic producers, since the U.S. prices are related to the overseas price. Any further reduction in return to producers will greatly increase the disincentive.

Thank you.

Mr. Anthony. I thank you for bringing that out. I had looked at those disruptions. That is one chart I plan on personally keeping because I think it shows what happened in the past and we know that history repeats itself. If we as Americans are going to be naive enough to think that we are not going to be facing another energy crisis in the future, then we are extremely naive. I can tell you just as one Member of Congress that if we don't do everything possible to develop the oil and gas industry, in addition to promoting alternate sources of energy, we are not only shortsighted, but one of these days we are going to wake up and be extremely sorry for it, and we are going to have an awful lot of young people asking why we didn't have the foresight to see it, do something about it, because they are going to be the ones suffering by our failure.

I think that is also part of the challenge of this Oversight Subcommittee, because not only were we to look at and make a record for tax policy, as to the different treatment of integrated companies, independents, and royalty owners, but also to find out whether or not that was good energy policy.

So it is interrelated, and your chart will certainly prove a valuable contribution in that particular area.

Well, this brings to a close 2 days of hearings that were requested by the full committee, to give the Oversight Subcommittee an opportunity to look at the tax treatment of oil and gas producers.

I want to personally thank all of the witnesses who have testified and especially those that had to wait until the very last panel on the very last day for your patience.

I also thank you for the chairman of the subcommittee and the chairman of the full committee.

With that, the Oversight Subcommittee will be in adjournment until call of the Chair.

[Whereupon, at 3:25 p.m., the hearing was adjourned.]

[Submissions for the record follow:]

**American Petroleum Institute**
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Charles J. DiBona
President

May 24, 1983

Mr. John J. Salmon, Chief Counsel
Committee on Ways and Means
U. S. House of Representatives
1102 Longworth House Office Building
Washington, D. C. 20515

Dear Mr. Salmon:

This submission on behalf of the American Petroleum Institute is in response to the press release dated April 15, 1983, announcing hearings on the tax treatment of producers of oil and gas.

The release stated that testimony would be received from persons desiring to comment on such proposals. The release further stated that instead of appearing in person, written testimony could be submitted for inclusion in the printed record of the hearing. The attached statement is submitted to satisfy that requirement.

Enclosed also is the Price Waterhouse study, "The Economic Impacts of the Intangible Drilling and Development Costs (IDC) Tax Provision on the Petroleum Industry," referred to in our statement. The American Petroleum Institute appreciates the opportunity to submit its comments, and if we can be of further assistance to the Committee by supplying additional material or information, please notify us.

Sincerely,

TO SUBCOMMITTEE

FOR THE RECORD

# STATEMENT OF THE

# AMERICAN PETROLEUM INSTITUTE

SUBMITTED TO THE

SUBCOMMITTEE ON OVERSIGHT

OF THE

COMMITTEE ON WAYS AND MEANS

U.S. HOUSE OF REPRESENTATIVES

Regarding

HEARINGS ON THE TAX TREATMENT

OF

PRODUCERS OF OIL AND GAS

Washington, D. C.

May 24, 1983

May 24, 1983

## SUMMARY

## I. PETROLEUM INDUSTRY PROFITABILITY, CAPITAL EXPENDITURES, AND TAXES

### A. Current Petroleum Situation.

These are troubled times for oil companies. Both demand and prices have dropped substantially from their peak level in 1979, causing a bleak profit outlook for oil companies. This has led to investor concern, and has required many oil companies to reassess and often reduce the scope of their operations, especially when they involve high-cost energy from unconventional sources or frontier regions. While oil demand has dropped sharply, the oil crisis is not over, and the industry's success in reversing the decline in U.S. production and diversifying foreign sources of supply would be seriously jeopardized by new or increased taxes.

### B. Movement of Oil Industry Profits.

There is a widely held misconception that oil industry profits move only up. Profits have sometimes risen and sometimes fallen. Recently, they have dropped precipitously. Moreover, those who argue that profits are ever higher ignore inflation and profitability (the relationship of profits to investment).

### C. Profitability.

Rate of return on investment is a far more significant indicator of performance than the absolute level of profits. Despite the high risks of petroleum exploration, oil company returns on shareholder equity have been above non-oil manufacturing returns in only four years since 1968 (1974, 1979, 1980, and 1981). In 1981, oil rates of return began falling once more, and by the end of 1982, the rate was about 14 percent with no adjustment for inflation -- in line with the industry's historic average.

### D. Capital Expenditures.

Increased profitability provides the incentive for growth in oil industry capital spending and much of the cash and borrowing capacity to finance new investments. Beginning in 1974, petroleum investment more than doubled, reflecting higher profits, and investment continued to climb through 1981. Decreasing profits have, however, led to reductions in planned expenditures. Increased capital expenditure led to more than a tripling of net additions to property, plant and equipment of the leading U.S. oil companies between 1974 and 1981 -- primarily for petroleum activities. Only about 8 percent of oil company capital expenditures have been for facilities outside the energy and petrochemical fields.

### E. Tax Burden.

In the face of receding demand and falling profits, the taxes paid by oil companies have remained high. The petroleum industry current federal income tax burden alone for 1982 was comparable to that of other companies -- 18.5 percent compared to 19.1 percent. Windfall profit taxes raised that figure to 43.4 percent, well above the tax burden of other industries -- exclusive of deferred income taxes (which are high in industries such as petroleum that invest heavily in new plants and equipment) and state severance and property taxes.

## II. AREAS OF DIFFERING TAX TREATMENT AMONG OIL AND GAS PRODUCERS

### A. Intangible Drilling and Development Costs.

1. Intangible drilling and development costs ("IDCs") are those costs incurred which, in themselves, have no salvage value and are "incidental to and necessary for the drilling of wells and the preparation of wells for the production of oil or gas." The option to deduct currently IDCs is intended to recognize that the search for new oil and gas reserves entails high-risk capital-intensive operations.

2. While the option is generally available, certain categories of taxpayers are treated differently in terms of: 1) the amount of IDCs which they are allowed to deduct currently; 2) the amount of IDCs as a tax preference item for purposes of the alternative minimum tax; and, 3) the alternatives allowed if a taxpayer chooses not to deduct currently IDCs.

The following chart summarizes IDC tax treatment for the different categories of taxpayers:

| Corporations which are integrated oil companies | Corporations which are independent producers | Individuals |
|---|---|---|
| 1) Currently deduct 85 percent of IDCs. Amortize 15 percent over 36 months | 1) Currently deduct 100 percent of IDCs | 1) Currently deduct 100 percent of IDCs |
| 2) Not a tax preference item | 2) Not a tax preference item | 2) Tax preference item if currently deducted |
| | | 3) May elect five-year ACRS with 10 percent ITC if not a limited partnership interest |
| | | 4) May elect ten-year amortization |

3. All producers, integrated or independent, should have the option to expense currently 100 percent of IDCs. Current expensing avoids the erosion in real value of capital cost recovery through

inflation when deductions are spread over a period of years.

4. To the extent that current expensing is not allowed, IDCs should be treated in the same manner as the tangible well investment eligible for five-year ACRS with a ten percent investment tax credit.

5. Current deductibility is important to the national effort to find and develop increased domestic petroleum supplies because it provides the investor with an improved cash flow in a high-risk, capital-intensive operation. The difficulty with present law is not that some types of oil and gas producers are allowed a 100 percent current deduction, but that some producers are restricted to 85 percent.

B. Percentage Depletion.

1. Percentage depletion is a capital cost recovery mechanism designed to encourage drilling activity and to approximate the cost of replacing reserves currently produced. The Tax Reduction Act of 1975 generally eliminated percentage depletion on oil and gas production while providing certain exemptions, including a limited exemption for independent producers and royalty owners.

2. Many of the underlying reasons for enacting percentage depletion in the first place justify its continuation today. Risks remain high; costs per barrel of new reserves have risen dramatically; and, perhaps most important, for the past decade domestic consumption has exceeded domestic reserve additions.

3. The use of "cost" depletion, based on historical cost, fails to take into account the true cost of replacing existing reserves. Income from the sale of these reserves represents consumption of a nonrenewable asset, and it is reasonable to consider the cost of replacing the reserves as the base on which recovery should be computed.

4. Rising prices through 1980 encouraged the oil and gas driller in finding oil and gas. In today's market, however, both demand and prices are down. Percentage depletion ameliorates the effect of this drop to some extent for independent producers. API believes that percentage depletion was and remains an effective replacement cost recovery mechanism which encourages production of oil and gas.

C. Windfall Profit Tax Deposit Dates.

1. The compliance system presently in effect for collection, deposit and reporting of windfall profit tax would be greatly simplified if there were no difference in the deposit dates for integrated and independent companies. Integrated companies must make deposits with the U.S. Treasury twice a month, while non-integrated companies make deposits 45 days after the close of the month in which the oil is produced.

2. The existing complex administrative system for collecting and depositing the tax, with its requirements of certificates and report

forms flowing both up and down the purchase chain, is cumbersome, repetitive and fraught with possibilities for errors.

3. Congress and the I.R.S. attempted to eliminate some of the complexity by providing elections for certain parties in the purchasing chain to be the withholding agent. Unfortunately, the difference in withholding dates discourages many parties from making the elections.

D. Stripper Oil Production.

1. Under the Crude Oil Windfall Profit Tax, stripper oil is placed in Tier Two and integrated producers pay a rate of 60 percent of the difference between the selling price and the adjusted base price. Independent producers' stripper production, whether otherwise classified in Tiers Two or Three, is exempted from the tax. An anti-transfer rule requires continued Tier Two taxation of stripper properties if they were ever held by integrated producers.

2. The original levy of the WPT on stripper properties was misguided because the production from the properties was already selling at market prices. (The exemption from price controls for "stripper oil" was first included in the Trans-Alaska Pipeline Authorization Act and subsequently modified by the Emergency Petroleum Allocation Act of 1973 and the Energy Conservation and Production Act.) There was thus no "windfall" to be derived from decontrol.

3. The disparate tax treatment between stripper properties held by integrated producers and those held by independent producers has led to disagreement as to how jointly operated properties would be managed, and the anti-transfer provisions have inhibited sales which could ameliorate operating differences.

4. The U.S. needs to maintain and increase stripper production, which amounts to about 12 percent of U.S. production. The economics and operation problems associated with stripper property are real regardless of size of the producer. Many stripper properties must be maintained as operational until enhanced recovery technologies become available. To maintain economic viability of stripper property, all stripper production should be exempt from WPT.

May 24, 1983

Appropriate tax treatment of oil and gas producers depends upon the nation's energy needs and economic priorities. Thus, before turning to specific aspects of tax treatment, this statement will review the current petroleum situation, oil industry profitability, the relationship between profits and capital expenditure, and, finally, the impact of industry tax burden on the nation's future energy security.

## I. PETROLEUM INDUSTRY PROFITABILITY, CAPITAL EXPENDITURES, AND TAXES

### A. Current Petroleum Situation

These are troubled times for oil companies. Oil consumption in both the U. S. and other industrialized OECD countries has fallen about 17 percent below its peak 1979 level; and in constant dollars, current Rotterdam spot prices are now about 40 percent below the heights reached during the 1979-80 oil crisis.

With falling oil demand and prices, the profits of U.S. oil companies have suffered. Among 22 major U. S. oil companies 1982 earnings were almost 30 percent below the peak level reached in 1980. In constant dollars (GNP deflator), 1982 profits were down nearly 40 percent. Investors are concerned that past expenditures made by oil companies in anticipation of high and rising prices are likely to be unprofitable with a possible further erosion of demand and price cutting. Indeed, many high-risk energy ventures have already been abandoned.

Oil companies are reassessing and often reducing the scope of their operations. For the first time since the early 1970's, the total capital expenditures of major U. S. oil companies turned down last year. While costly outlays on oil exploration and development proceeded at record high levels in 1982 -- some 5 times the 1972 spending level in current dollars -- current and future investment plans are now being reevaluated and sometimes cut back, especially when they involve high-cost energy from unconventional sources or frontier regions.

## B. Movement of Oil Industry Profits and Profitability

Chart I shows worldwide profits of leading U. S. oil companies for the period 1968-1982 in both current and constant dollars. When the real buying power of a profit dollar is considered, the 1982 profit figure of about $20 billion is equivalent to $8 billion in 1968 dollars -- roughly equal to average earnings for 1973-74. This adjustment for inflation is conservative since it is based on the implicit price deflator for U. S. Gross National Product, which has risen much less rapidly than the cost of oil exploration and production since the early 1970's. Exploration and production expenditures account for about two-thirds of petroleum capital outlays.

The rate of return on investment is a far more significant indicator of an industry's performance than is the absolute level of profits, which ignores the level of investment. Increased investment can be justified only by anticipation of more profits. Furthermore, return on investment is the only economically sound method of comparing one industry's profitability with another's. The most widely used measure of return on investment is net income as a percent of shareholders' equity.

According to Citibank, worldwide return on equity was higher for non-oil manufacturing companies than for oil companies in three of the five years, 1968-1972, despite the high degree of risk inherent in petroleum exploration (see Chart II). As oil prices increased in 1973 and 1974, the oil companies' rates of return rose above non-oil manufacturing. However, oil returns were again below non-oil manufacturing during 1976-1978. Thus, the oil price increases of 1973-74 only temporarily raised oil industry profitability above other industries. For the latest four years, 1979-1982, oil company returns have remained above non-oil company returns, but the difference has narrowed greatly since 1980. By the end of 1982, the oil rate of return on shareholder investment was about 14 percent with no adjustment for inflation -- in line with the industry's historic average.

## C. Capital Expenditures

Increased profitability provides the incentive for growth in oil industry capital spending. It also provides much of the cash and borrowing capacity required to finance new investments. As Chart III shows, capital expenditures move closely with profits, but there is a lag because of commitments already made on projects having relatively long lead times.

While profits were about constant during 1968-1972, capital expenditures were also constant. Beginning in 1974, petroleum investment more than doubled, reflecting higher profits. The average level of profits during 1974-78 was also about twice the 1968-1972 level:

| | Profits | Billion Dollars | Capital Expenditures |
|---|---|---|---|
| 1968-72 Average | $5 | | $9 |
| | +6 | | +11 |
| 1974-78 Average | 11 | | 20 |
| | +16 | | +23 |
| 1980-81 Average | 27 | | 43 |
| | -7 | | +3 |
| 1982 | 20 | | 46 |

By 1980-81, profits were up by another $16 billion and capital expenditures were up by $23 billion. The larger absolute increase in capital expenditures was made possible by rising profits. During 1982, capital expenditures were still $3 billion above the 1980-81 average even though profits were some $7 billion lower. And, comparing 1982 with 1981 alone, although 1982 expenditures were 6% lower ($46 billion versus $49 billion), they still fell less than the 25% drop in profits ($20 billion versus $27 billion) because of the lag created by investment in long lead time projects.

The increased capital expenditure noted above led to more than a tripling of net additions to property, plant and equipment of the leading U. S. oil companies between 1974 and 1981. And, as Chart IV illustrates, the additions were primarily for petroleum activities. The spending has especially stimulated new oil production in non-OPEC countries. Production of crude oil has even been increased somewhat in the United States after a decade-long downward trend.

## D. Tax Burden

In the face of receding demand and falling profits, the taxes paid by oil companies have remained high. Total Crude Oil

Windfall Profit Tax ("WPT")[1] collections in the United States increased from $10 billion in 1980 to about $26 billion in 1981 and then, with falling crude oil prices, declined to $17 billion in 1982 (before allowance for income tax offset). In combination with other federal and state taxes on oil output and income, the effect of the WPT has been to strip about 80 cents of each additional dollar of oil company revenue due to U.S. oil price decontrol.

Combined U.S. current federal income tax and WPT liabilities incurred by a representative group of oil companies grew to $23 billion in 1981 from $14 billion in 1980, before falling back to $14 billion in 1982. Because U.S. income before these taxes rose at a slower rate, the oil companies' effective U.S. federal tax rate (current federal income taxes plus the WPT divided by income before such taxes) increased from 26 percent in 1979 to 41 percent in 1980, 50 percent in 1981 and then declined to 43 percent in 1982. These data do not reflect the practice of state and local governments of taxing U.S. oil producers more heavily [illegible] other kinds of companies. In particular, these figures [illegible] the billions of dollars of severance taxes and property [illegible] oil and gas reserves paid by U.S. oil producers.

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[1] The WPT properly should be considered a part of the oil industry's federal tax burden even though it is an excise tax. Inasmuch as the WPT is imposed directly on a portion of crude oil revenues, the exclusion of the tax would significantly distort the industry's tax burden relative to that of all other industries which are not subject to such a tax.

Chart V compares the partial tax burden of the U.S. oil industry and other U.S. companies for 1979 through 1982. The oil industry graphs display two factors: the combined Windfall Profit Tax and current U.S. federal income tax burden as well as the estimated level of petroleum industry federal income tax had the Windfall Profit Tax not been enacted. Deferred federal income taxes (which arise primarily from the difference between accelerated and economic-life cost recovery) are excluded. Deferred income taxes are highest for industries, such as petroleum, which are investing in new plant and equipment.

Even though the oil industry's tax burden is already the highest in the country, some have suggested additional levies on oil producers. New or increased taxes would further reduce returns on investment and sources of funds to an industry already hurt by declining demand and prices. As a result, oil companies would be further constrained in their efforts to find and develop new energy supplies. Such a reduction would jeopardize the progress made in recent years to reduce the world's dependence on OPEC oil.

While oil demand has dropped sharply in recent years and may continue to drop in the years ahead, it is dangerously premature to conclude that U.S energy problems have ended. Imports still account for about one fourth of U.S. crude oil requirements. The success that oil companies have had in reversing the decline in U.S. oil production and diversifying oil supplies worldwide ought not to be undone through the imposition of new taxes. The advantage of hindsight makes it clear that the U.S. energy crisis of the 1970's could have been resolved at far lower economic and political cost if only U.S. oil prices had been decontrolled earlier and U.S. oil producers had been taxed less.

Private investment, responding to relative rates of return, is the most effective method of allocating capital resources throughout the economy. Interference with this process diminishes the economy's efficiency. Thus, taxing petroleum even more, relative to other industries, would discourage energy investment just as the country is making encouraging progress in the quest for energy security.

## II. AREAS OF DIFFERING TAX TREATMENT BETWEEN OIL AND GAS PRODUCERS

### A. Intangible Drilling and Development Costs

Under Sec. 263(c) of the Internal Revenue Code and Treasury Regulations promulgated thereunder, taxpayers are granted the option to deduct currently intangible drilling and development costs ("IDCs") for oil and gas wells and wells drilled for geothermal deposits. IDCs are costs incurred which, in themselves, have no salvage value and are "incidental to and necessary for the drilling of wells and the preparation of wells for the production of oil or gas." Treas. Reg. §. 1.612-4(a). Such costs expressly include wages, fuel, repairs, hauling, supplies, etc.

The deduction for IDCs, which has been in existence since 1913, is intended to recognize that the search for new oil and gas reserves entails high-risk, capital-intensive operations. The deduction of IDC expenses contributes to the national effort to find and develop domestic petroleum supplies because it provides the investor with an improved cash flow return on investment. According to a recent study, the additional exploration and development activity stimulated by this cash flow advantage results in revenue from income taxes and Windfall Profit Tax well in excess of any temporary postponement of income tax attributable to the current deduction.[2]

Moreover, as the Committee on Ways and Means properly concluded in its House Report 97-201, at page 17, current expensing avoids the erosion in real value of capital cost recovery through inflation when deductions are spread over a period of years. Thus, while the five year Accelerated Cost Recovery System ("ACRS") with a ten percent investment tax credit ("ITC") may be comparable to current expensing at the four to six percent inflation rates implicit in a ten percent discount rate, it fails to provide adequate recovery at the steeper inflation rates recently experienced.

With respect to the tax treatment of IDC expenditures, certain categories of taxpayers are treated differently in terms of: 1) the amount of IDCs which they are allowed to deduct currently; 2) the treatment of IDCs as a tax preference item for purposes of the alternative minimum tax; and, 3) the alternatives allowed if a taxpayer chooses not to deduct IDCs currently.

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[2] The Economic Impacts of the Intangible Drilling and Development Costs ("IDC") Tax Provison on the Petroleum Industry, April 1983, prepared for the American Petroleum Institute by Price Waterhouse.

Sec. 291(b), which was added to the Internal Revenue Code by the Tax Equity and Fiscal Responsibility Act of 1982 ("TEFRA"), reduces the amount of current IDC deductions by 15 percent for all corporations that are integrated oil companies. The 15 percent is allowed as a deduction ratably over a 36-month period beginning with the month in which the costs are paid or incurred. Sec. 291(b)(2)(A). These amounts are not eligible for investment tax credit and are also subject to recapture under Sec. 1254 if the property is later disposed of. In contrast, corporations which are nonintegrated oil companies are allowed to deduct currently 100 percent of their IDC expenditures. None of the IDC amounts which are expensed or amortized by corporations, integrated or independent, are treated as tax preference items.

All individuals are allowed to elect to deduct 100 percent of their IDC expenditures. However, if an individual elects to deduct the full amount, he must include the amount of "excess intangible drilling and development cost" as a tax preference item for purposes of the alternative minimum tax.

TEFRA repealed the add-on minimum tax and substantially revised the alternative minimum tax for noncorporate taxpayers effective for years after 1982. The alternative minimum tax for noncorporate taxpayers is 20 percent of the excess of alternative minimum taxable income over the exemption amount, limited to the extent it exceeds regular tax liability. Sec. 55(a). The amount of alternative minimum taxable income equals adjusted gross income (excluding net operating losses) increased by tax preference items and reduced by certain itemized deductions and separately computed net operating losses. One of the preference items included in this calculation of the alternative minimum tax is "excess intangible drilling and development costs". Sec. 57(a)(11). "Excess IDCs" are deductible IDCs incurred during the taxable year less the amount, if any, that would have been deductible in the same year if the taxpayer had amortized the expenses for that year over 120 months beginning with the month of first production or less that amount of cost depletion that would have been deductible in the first year. The amount of IDCs which are treated as a tax preference item is limited to the amount by which the taxpayer's excess IDCs "exceeds its net income from oil and gas properties for the year."

Since only the first year's allowance for cost recovery is recognized for alternative minimum tax purposes, the amount of the IDC preference is substantially overstated. Moreover, the use of 120 months amortization or cost depletion overlooks the fact that such costs, when capitalized, are treated as depreciable for financial accounting purposes in the same manner as the tangible well equipment. As such, five-year ACRS treatment coupled with ITC which is used for tangible oil producing investment would appear to be a more logical measure of the "preference", if any.[3]

The inclusion of excess IDCs as a tax preference item can be avoided if the individual elects to deduct the costs ratably over a ten-year period under Sec. 58(i)(1) or under a five-year schedule similar to ACRS under Sec. 58(i)(4), depending on whether the IDCs are attributable to a limited partnership interest. Taxpayers who have limited partnership interests may elect the ten-year amortization beginning with the taxable year in which the expenditures are made. Individuals who have IDCs which are not allocable to limited partnership interests may elect to treat the expenditures as the acquisition of five-year Sec. 1245 property and may depreciate the expenditures under an accelerated cost recovery method. Sec. 58(i)(4). If the five-year recovery method is elected, the expenditures will be treated as qualified Sec. 38 property for purposes of the investment tax credit. Upon the sale of the oil or gas property, the deductions will be treated as deductions allowable under Sec. 263(c) for the purposes of the recapture rules of Sec. 1254.

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[3] The current treatment of capitalized IDC as a depletable investment under Treas. Reg. Sec. 1.612-4(b) is not based on sound tax accounting theory, but on a questionable IRS interpretation of the discovery value depletion provisions of the Revenue Act of 1918. IDCs were originally treated as depreciable investment if the taxpayer did not elect to deduct them currently. (T.D. 2447, February 8, 1917.) With the advent of discovery value depletion in 1918, the IRS changed its position and contended that the depletable value of the well included capitalized IDCs except to the extent they were represented by physical property which was still considered depreciable. (Regulations 45, Art. 223.) The IRS continued to take the same position after percentage depletion was substituted for discovery value depletion in 1926. (Treas. Reg. Sec. 1.612-4(b) -- current regulations.) With repeal of percentage depletion on most production, there clearly is no basis for continuing to characterize any portion of IDCs as depletable investment.

The following chart summarizes the IDC tax treatment for different categories of oil and gas producers:

| Corporations which are integrated oil companies | Corporations which are independent producers | Individuals |
|---|---|---|
| 1) Currently deduct 85 percent of IDCs. Amortize 15 percent over 36 months | 1) Currently deduct 100 percent of IDCs | 1) Currently deduct 100 percent of IDCs |
| 2) Not a tax preference item | 2) Not a tax preference item | 2) Tax preference item if currently deducted |
| | | 3) May elect five-year ACRS with 10 percent ITC if not a limited partnership interest |
| | | 4) May elect ten-year amortization |

As is illustrated by the above discussion, individuals (except for holders of limited partnership interests) and corporations which are independent producers receive tax treatment with respect to IDCs which allows for 100 percent current deduction or comparable five-year ACRS depreciation with investment tax credit. However, corporations which are integrated oil companies are only allowed to deduct currently 85 percent and are relegated to a very complex and burdensome 36 month amortization in lieu of five year ACRS with ITC on the balance. To the extent current expensing is not allowed, IDCs should be treated in the same manner as the tangible well investment eligible for five-year ACRS with a ten percent investment tax credit. Any other approach would not be logical, equitable or in accord with sound tax accounting theory.

The API has consistently supported the position that all producers, integrated or independent, should have the option to expense currently 100 pecent of the IDCs which they expend in the drilling of oil and gas wells. The current deductibility of IDCs is an efficient tax mechanism, and the difficulty with present law is not that some types of oil and gas producers are allowed a 100 percent current deduction but that some producers are restricted to 85 percent.

Current deductibility is important to the national effort to find and develop increased domestic petroleum supplies. Because the current deduction provides the investor with an improved cash flow, its elimination would hamper the search for new oil and gas reserves. Many high cost marginal domestic projects would lose their economic viability. The nation and the consuming public would be forced to rely increasingly on foreign sources of petroleum supply.

## B. Percentage Depletion

The Tax Reduction Act of 1975 added Sec. 613A of the Internal Revenue Code to eliminate percentage depletion on oil and gas production. Certain exemptions were provided, however, including a limited exemption for independent producers and royalty owners. API believes that percentage depletion was and remains an effective replacement cost recovery mechanism which encourages exploration and production of oil and gas by recognizing the high risks and the enormous capital outlays required to replace reserves today in the industry.

Depletion is a capital recovery mechanism. An owner of an interest in an oil, gas or mineral property incurs costs which, for tax purposes, are considered capital in nature. These include acquisition costs, such as lease bonuses, which are capital for financial and tax purposes and certain other costs, such as geologic and geophysical exploration costs, which are considered an expense item by accounting standards but are capitalized for tax purposes.

This capital must be recovered by "cost" depletion if percentage depletion is unavailable. Cost depletion is typically taken by the unit-of-production method -- which limits current capital cost recovery to an estimate of how much of the property's total remaining output is represented by current production. Thus, when a barrel of oil is produced, it is ratioed with remaining reserves and multiplied by the adjusted tax basis of the property involved to determine the amount of the current depletion deduction. For a long-lived property, this method of recoupment is the slowest method of capital recovery available under current law. Real costs of capital invested have thus been "underrecovered" in recent years primarily due to the effects of inflation. By contrast, ACRS investors in manufacturing plant and equipment are able to recoup their investment within a minimum of five years after operation begins, even if the expected productive life of the investment is longer.

Congress first adopted percentage depletion in 1926 as a replacement for "discovery value depletion".[4] Percentage depletion is designed to encourage drilling activity and to approximate the cost of replacing reserves currently produced. Depletion calculated on the percentage method allows the owner of the oil or other wasting natural resource to recover a percentage of gross income subject to certain limitations. In the case of oil and gas, the current rate of percentage depletion is 16%; the rate is permanently reduced to 15% beginning in 1984. These rates are substantially below the current value of reserves in the ground as a percentage of wellhead price (about 25%).

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4. (See Appendix for discussion of history of percentage depletion prior to 1969.)

Many of the underlying reasons for enacting percentage depletion initially, i.e. high risk and high cost, justify its continuation today. Risks remain high; in 1982 the industry experienced dry holes on 70% of all wildcat wells drilled. Furthermore, costs per barrel of new reserves have risen dramatically. Finally, and perhaps most importantly, in the past several years domestic consumption has exceeded domestic reserve additions.

The elimination of percentage depletion on oil and gas production of integrated oil companies in 1975 was, in part, a political reaction to the dramatic increases in oil prices that occurred after the Arab oil embargo. The retention of percentage depletion on certain limited production for eligible producers enables such operators to obtain the risk capital necessary to drill prospects which have been made uneconomic for non-eligible producers due to the removal of percentage depletion. The marginal prospect remains important in the outlook for potential additions to domestic reserves.

U. S. proved reserves steadily declined from 1970 through 1980 despite increased oil prices and record capital outlays by the oil and gas industry. Over the same period, the cost of replacing reserves rose dramatically. Inflation, which affects all business, contributed to the increase in geological and geophysical costs, as well as lease bonuses. Also, potential reserve additions were located in deeper zones or in otherwise more operationally difficult, and hence expensive, areas like deep offshore waters, the Alaskan Arctic, etc. Drilling costs escalated as wells were drilled deeper, the cost per foot drilled increased and reserves discovered per well drilled became smaller.[5] While the rate of the increase in these costs has slowed, and indeed some of the costs have actually declined since the 1981 peak, the use of historical cost as a base for computing depletion simply fails to take into account the true cost of replacing existing reserves, especially when costs have increased as they have in the last decade. The income generated by the sale of production from these reserves represents the consumption of a nonrenewable capital asset. As such, it is reasonable to consider the cost of replacing the reserves as the base on which recovery should be computed, rather than historical cost.

Rising prices through 1980 encouraged the oil and gas driller in finding oil and gas. Undoubtedly, however, some wells were not drilled and some production was forfeited by the removal of percentage depletion for integrated oil companies. In today's market, however, the demand for oil and gas products has declined, resulting in a corresponding decrease in price. Percentage depletion ameliorates the effect of this decline to some extent for independent producers.

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[5] (See statistics contained in the Annual Survey of Oil and Gas, published by the Bureau of the Census, and the Joint Association Survey.

## C. Windfall Profit Tax Deposit Dates

The compliance system presently in effect for collection, deposit and reporting of windfall profit tax would be greatly simplified if there were no difference in the deposit dates for integrated and independent companies. Integrated companies required to withhold the windfall profit tax must make deposits with the U.S. Treasury twice a month under Sec. 4995(b) while nonintegrated companies make deposits 45 days after the close of the month in which the oil is produced. This disparity in deposit dates adds complexity to an already complex administrative system for collecting and depositing the windfall profit tax. Situations in which there are intermediate disbursers (i.e., the party removing the oil from the premises is not making payment directly to each producer) are causing unnecessary administrative burdens on the industry and audit burdens on the IRS. These situations are not uncommon and are creating confusion in all areas of compliance, including certifications, withholding and annual information reporting.

Producers must provide certain certificates to the operator, partnership or disburser who distributes the payments due on the oil. This disburser, if an intermediary, must in turn accumulate the information and pass it on to the party from whom payment is received until the information reaches the party required to make deposits. The procedure is cumbersome, repetitive and results in errors in deposits and withholding.

When a year is completed and Form 6248 must be prepared, the process is reversed with the original form prepared by the party required to make deposits and furnished to the intermediary who in turn must analyze and reconcile the forms to his own records and then prepare new Forms 6248 to be furnished to each producer to whom he makes payments. This procedure is also cumbersome, repetitive and results in errors.

Congress and the Internal Revenue Service seemed to have recognized the logic of getting the withholding and depositing closer to the ultimate producer in order to eliminate these problems, by providing an operator/purchaser election, but the rules are still too restrictive. The operator/purchaser election provided by Sec. 4995(a)(7) does allow the operator to act as the withholding agent in place of the purchaser. However, if the operator is not an integrated oil company, he assumes the withholding and depository obligations of the purchaser which, if the purchaser is integrated, will include twice a month deposit obligations. Independent producers are understandably reluctant to take on these accelerated depository responsibilities because of the loss of cash flow involved, particularly with respect to amounts that must be deposited before payment is received from the purchaser.

The qualified disburser election provided by regulations is also restrictive. Because of the cash flow detriment inherent in twice monthly deposits, many integrated companies are also reluctant to make the qualified disburser election. If the cash flow detriment of the integrated deposit rules were eliminated, the result would be many qualified disburser elections. More qualified disbursers would eliminate many of the compliance difficulties and simplify the audit efforts of the Internal Revenue Service because the depositing party would be much closer to the producer in the cash payment chain.

## D. Stripper Oil Production

An exemption from price controls for "stripper oil" was first included in the Trans-Alaska Pipeline Authorization Act and subsequently modified by the Emergency Petroleum Allocation Act of 1973. In November of 1975, the Energy Policy and Conservation Act placed price controls on stripper oil for a brief period. It was decontrolled again in August, 1976 by the Energy Conservation and Production Act. A property permanently qualified for the stripper exemption once the average daily production per well dropped to ten barrels or less per day for a 12 month period.

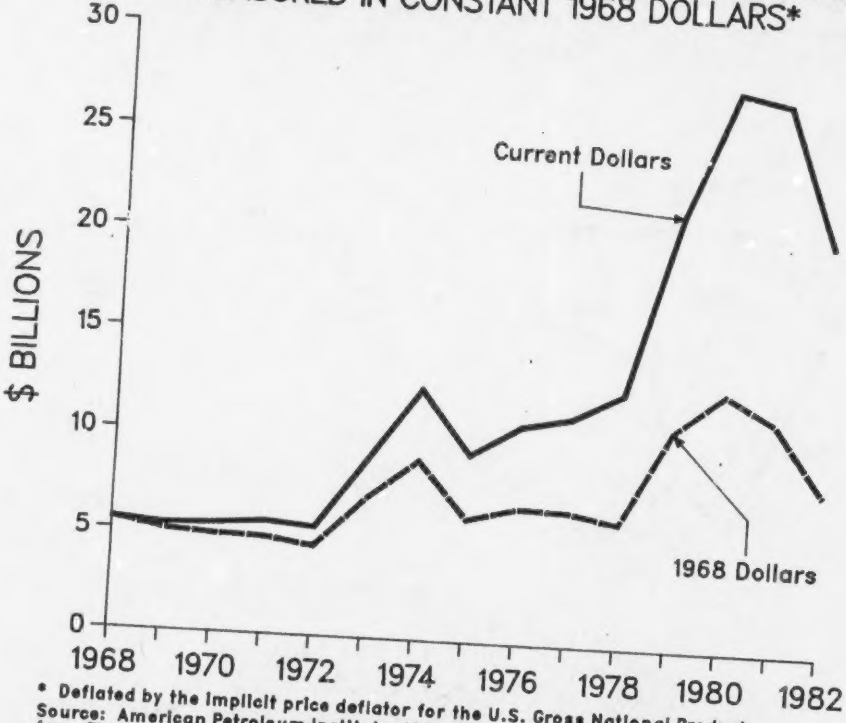
The Crude Oil Windfall Profit Tax categorizes stripper production as Tier Two oil, and the rate for integrated producers is 60 percent of the difference between the selling price and the base price as adjusted for severance tax and inflation, as well as differences in quality and location. The Economic Recovery Tax Act of 1981 exempted independent producers' stripper production from the WPT. An anti-transfer rule requires continued Tier Two taxation of stripper properties if they were ever held by integrated producers. This disparate tax treatment between stripper properties held by integrated producers and those held by independent producers has led to disagreement as to how jointly operated properties would be managed, and the anti-transfer provisions have inhibited sales which could ameliorate operating differences.

The original levy of the WPT on stripper properties was misguided because the production from the properties was already selling at market prices. There was thus no "windfall" to be derived from decontrol. The levy of the WPT on stripper properties caused an immediate reduction in wellhead realizations which has unquestionably caused production declines and premature abandonment of stripper properties. These production declines and abandonments will increase unless the WPT levy on all stripper production is removed. Moreover, income tax revenues far in excess of the WPT revenues extracted from the prematurely abandoned properties very likely will be lost.

The U.S. needs to maintain and increase stripper production. It should be recognized that the economics and operational problems associated with a stripper property are real and valid, regardless of the overall size of the producer. The cost of materials and labor are the same to both. Thus, to maintain economic viability of the stripper property, all stripper production should be exempt from the WPT. Another important consideration is that many stripper properties must be maintained as operational until various enhanced recovery technologies are proven and can be economically applied to the property. Only by allowing the operator of a stripper property to retain the maximum income from this property can the United States be assured that this potential source of crude oil will be available for application of tertiary recovery techniques as the technology unfolds.

In summary, stripper properties amount to about 12 percent of U.S. production, and integrated companies are substantial stripper oil producers. The original levy of the WPT and its continued levy on stripper properties for integrated producers is counterproductive to our country's economic well-being and our goal for greater energy independence.

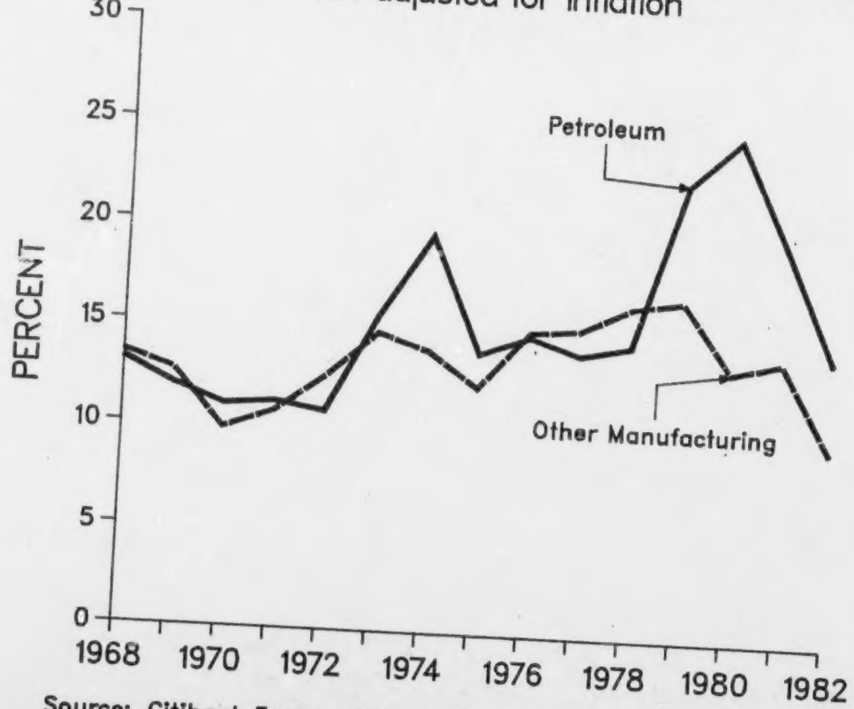
## CHART I
## WORLDWIDE PROFITS OF 22 U.S. OIL COMPANIES, 1968–1982 AS REPORTED IN CURRENT DOLLARS VS. BUYING POWER MEASURED IN CONSTANT 1968 DOLLARS*



* Deflated by the implicit price deflator for the U.S. Gross National Product
Source: American Petroleum Institute, 1981 data are preliminary
from Financial Reporting System, based on 1982 EIA Annual Energy Review

CHART II

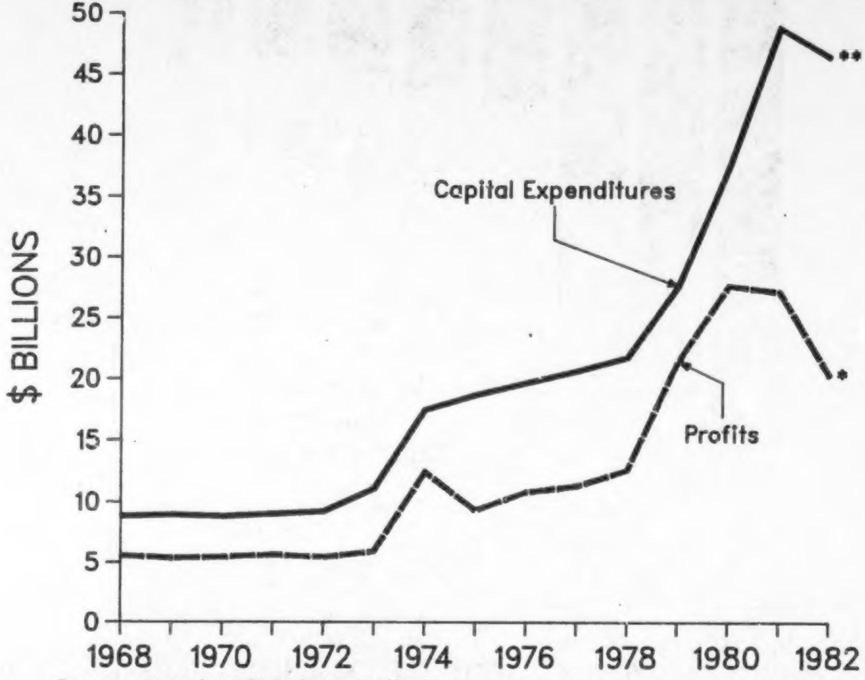
WORLDWIDE RETURN ON SHAREHOLDER EQUITY, 1968–1982
U.S. OIL COMPANIES VS. OTHER MANUFACTURING
not adjusted for inflation



Source: Citibank Economic Week, April issues

CHART III

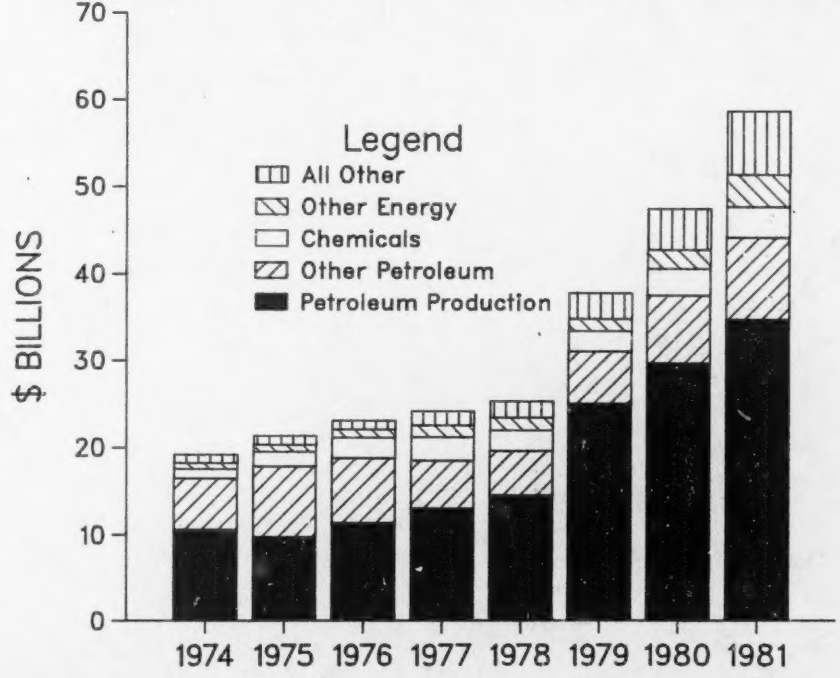
## WORLDWIDE PROFITS AND CAPITAL EXPENDITURES OF 22 U.S. OIL COMPANIES, 1968–1982



Source: American Petroleum Institute
* 1982 profit figures, preliminary
** 1982 expenditure figures, estimates

CHART IV

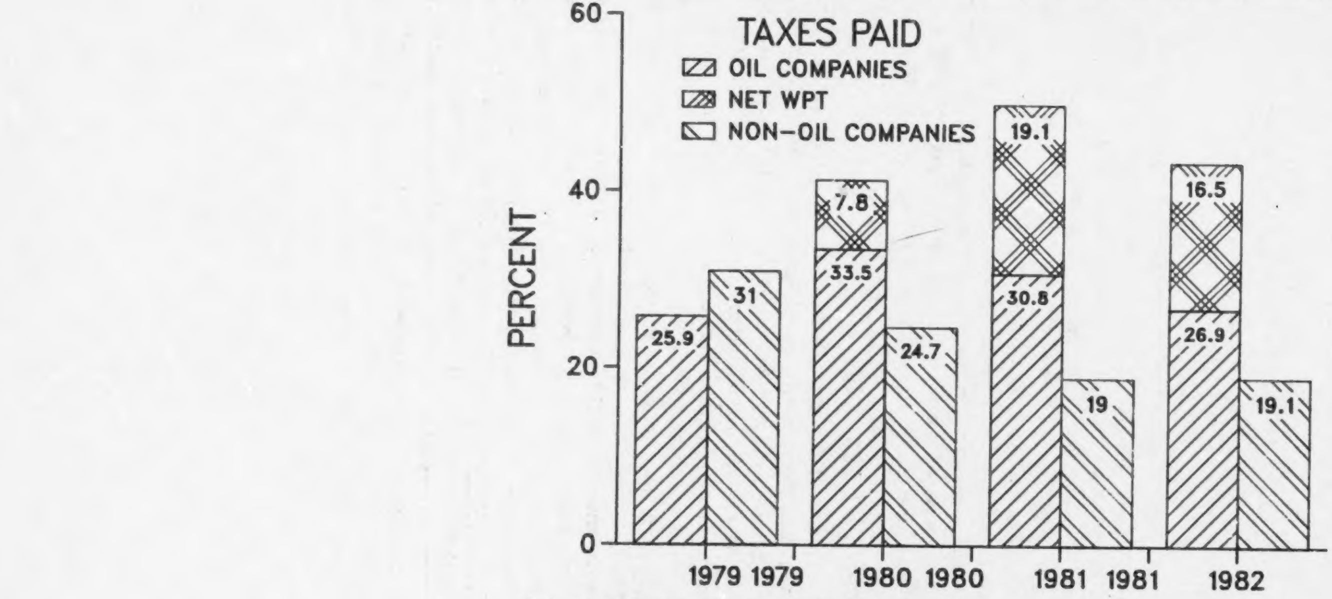
## WORLDWIDE ADDITIONS TO PROPERTY, PLANT AND EQUIPMENT OF 26 U.S. OIL COMPANIES



Source: Energy Information Administration, U.S. Dept. of Energy

## CHART V

# COMPARATIVE FEDERAL TAX BURDEN OF LEADING U.S. OIL AND NON-OIL INDUSTRIAL COMPANIES



Source: Corporate
Annual Reports
to Stockholders

1979: 23 Oil Companies and 86 Non-oil Companies
1980-1982: 20 Oil Companies and 75 Non-oil Companies

Note: Oil income taxes shown for 1980-1982 are what would have been paid without the Windfall Profit Tax, which is shown net of the income tax offset. In the WPT computation procedure, the WPT is deducted from income; and income tax is levied on the residual. If there were no WPT, the income tax would be higher --as shown above.

# LEGISLATIVE HISTORY OF PERCENTAGE DEPLETION FOR OIL AND GAS PRODUCTION

In framing legislation to implement the first income tax law under the Sixteenth Amendment—the Revenue Act of 1913—Congress found that defining "income" was a problem. It was fairly easy to determine what constituted the income of a salaried worker or wage earner, but in other cases complications arose. The extractive industries, such as coal mining, metal mining, and oil and gas production, presented a problem. The basic problem was one of distinguishing between capital and income in computing the tax, and one of the most important aspects of the problem related to depletion—the gradual exhaustion of the resource as the well or mine was operated.

## Early Depletion Legislation

The first efforts of Congress to solve this capital-income difficulty were made in connection with the Revenue Act of 1913 which granted taxpayers in the extractive industries ". . . a reasonable allowance for depletion of ores and all other natural deposits" in computing their income tax, and limited the deduction to 5 per cent of the gross value of the production for the year. The deduction during the life of the property was not to be greater than the original cost of the property, or the market value as of March 1, 1913.

In the Revenue Act of 1916, Congress changed the 5 per cent limitation in the case of oil and gas wells to "a reasonable allowance for actual reduction in flow." The capital to be recovered was not to exceed the larger of the "capital originally invested" or the March 1, 1913 "fair market value." To compute the depletion deduction, it was necessary to estimate the amount of oil remaining in a property, divide this estimate into the larger of the two capital measures, and multiply by the number of barrels produced during the taxable year. For example, if the capital to be recovered for a given property was $50,000, and if it was estimated that 100,000 barrels remained to be recovered from it, the depletion deduction would be $0.50 per barrel of oil produced. If production for a year was 2,500 barrels, the depletion deduction would be $0.50 x 2,500, or $1,250. This amount was simply a return of capital, and not income.

The fair market value of an oil property very often has no relation to its original cost. A resource discovered in the earth may have, or can acquire, value far in excess of the cost of its discovery. The total discovery cost of a wildcat well, for example, might be $100,000, but its actual value once discovered could be many times that amount, and the discoverer could actually sell the property for the higher amount if he did not wish to operate it.

Tax inequities naturally resulted from the 1916 provisions because depletion on a property that was productive as of March 1, 1913 was computed on its value as of that date, whereas depletion on a property which became productive after that date was determined on cost. Before World War I, when the corporate income tax rate did not exceed 2 per cent, the disparity between the tax treatment of individual properties did not produce significant differences in results, but this situation changed with the advent of high income tax rates after the United States entered World War I.

## The Discovery Depletion Principle

The Revenue Act of 1918 took this disparity into account and extended the application of fair market value as a basis for depletion to newly discovered oil wells, gas wells, and mines. Thus, a producer who discovered a property after March 1, 1913, was put on an equal tax footing with those who had made discoveries before that date. He was enabled, in other words, to compute depletion on the discovery value of his property. Discovery value was defined as the amount of money the producer could obtain were he to sell his property within thirty days after discovery. He could then use this figure in computing that part of the revenue from the property which represented a diminution, or depletion, of his capital.

Though discovery depletion continued to be approved by several successive Congresses, its provisions proved difficult to administer. The Bureau of Internal Revenue was the scene of endless controversies over the determination of "fair market value" of every mine, oil well, or gas well within thirty days after discovery. This was often a difficult and expensive task, entailing complicated engineering analyses, frequent differences of opinion between owners and the government, and long delays in settling tax cases. The whole situation aroused so much dissatisfaction that a Select Senate Committee was appointed to study the matter.

The Committee confirmed that the law was difficult to administer. But experience had shown that the discovery value per barrel of oil, as established by appraisal of individual properties, bore a reasonably consistent relationship to the price of crude oil at the well as it was produced. It seemed, therefore, that the whole procedure of fixing a proper depletion allowance could be simplified by allowing depletion on the basis of a fixed percentage of the gross income obtained from the oil drawn out of the earth. Early in 1926 the Committee reported its findings and proposed such a substitute for discovery depletion.

## Percentage Depletion

After receiving the Select Committee proposal, the Senate Finance Committee made a study of the problem and presented a report to the Senate recommending the adoption of "percentage depletion" in the following words:

> The administration of the discovery provision of existing law in the case of oil and gas wells has been very difficult because of the discovery valuation that had to be made in the case of each discovered well. In the interest of simplicity and certainty in administration, your committee recommends that in the case of oil and gas wells the allowance for depletion shall be 25 per cent of the gross income from the property during the taxable year.

Senator Reed of Pennsylvania, in supporting the subsequent bill, observed that 25 per cent represented an average of actual experience with oil properties and that it would achieve about the same results as discovery value depletion without the guesswork involved in the latter. "If there is any error in the 25 per cent figure," he said, "it is in favor of the government." He then went on to discuss the problem:

> We provide that the owner of an oil well or a mine who is exhausting his capital when he takes out the mineral can chalk off an allowance for depletion of his property. That sounds simple; but when we come to apply that, the application is so complicated that it causes a large part of the disagreement between the taxpayers and the bureau. If Senators will think for a moment about the application of that rule to an oil well, it will be realized that the owner of the well is exhausting his capital every time he draws a barrel of oil out of the well, so part of the value of that oil is in there and part of it is a mere return of his capital. In order to calculate what part of it he can charge off to depletion, the bureau has been estimating the quantity of oil in the property, which is just about as hard as estimating the quantity of air over the

> property. Then, on top of that estimate, they try to estimate what that oil will be worth in the market in future years, which multiplies the first uncertainty by a second uncertainty, and, of course, no two people ever agree on that . . . We have taken a big step forward in this bill, in our committee amendment, which provides that an arbitrary percentage of the gross selling value of that oil shall be deducted to allow for depletion. The owners of some of the oil wells say that we have not allowed enough, and some of the experts of the bureau say they think perhaps we have allowed a little too much. Probably we have been reasonably fair. But the whole thing is in the line of simplification, getting rid of this everlasting accounting.

The percentage figure was discussed at some length in the Senate. Senator Neely of West Virginia thought it necessary to increase the rate to 35 per cent in order to protect the small operator, and Senator Goff of the same state introduced an amendment providing for either a 35 or 40 per cent deduction depending on the relation of operating expenses to gross income during the taxable year. Both proposals were defeated, and a 30 per cent figure was agreed upon when the Senate adopted the bill.

The House Ways and Means Committee had agreed to recommend 25 per cent of gross income as a proper depletion deduction for oil and gas, and the compromise figure of 27½ per cent was finally established by the House and Senate Committees in conference. By the Revenue Act of 1926, then, percentage depletion at 27½ per cent was substituted for discovery depletion and made retroactive to January 1, 1925. Like discovery depletion, it applied to oil and gas production of United States taxpayers wherever their operations were conducted, whether in the United States or elsewhere. Though subject to constant review and suggested change, percentage depletion for oil and gas production has remained in effect at that figure ever since.

Fundamentally, percentage depletion is not a departure from the discovery value depletion provision of the Revenue Act of 1918. The main difference between them is in the technique of calculating the amount of the deduction. Under discovery value the deduction is based on the appraised value of the estimated reserves of oil at the time of discovery, but under percentage depletion it is based on the wellhead value of the oil as it is produced.

The current average price being paid for proved undeveloped reserves is about $0.93 a barrel, and the average wellhead price of crude oil today is about $2.88 a barrel. At that price, the maximum percentage depletion deduction at 27½ per cent is about $0.79, which is lower than the going price of undeveloped reserves. (In actual practice the depletion deduction on many properties would be less than $0.79 because it is limited to 50 per cent of net income.) It would appear, therefore, that percentage depletion recovers somewhat less than the capital value that would be recovered under discovery value depletion.

## The Limitation to 50 Per Cent of Net Income

The Revenue Act of 1921 provided that the depletion deduction should not exceed the net income from the property before deducting depletion. For example, if the net income from a well was $25,000 before depletion, and the depletion, figured on the value of the property at the time it was discovered, came to $40,000, the taxpayer could not take more than $25,000 as his depletion deduction for the year. In its report, the Senate Finance Committee urged this limitation ". . . in order to make certain that the depletion deduction when based upon discovery value shall not be permitted to offset or cancel profits derived by the taxpayer from a separate and distinct line of business."

In 1921, the Treasury Department had strongly recommended that the discovery depletion deduction be limited to 50 per cent of the net income from the property, and in the Revenue Act of 1924 this proposal was adopted. Thus, beginning in 1924 the taxpayer in the above example was required to reduce his depletion deduction to $12,500—that is, 50 per cent of his net income.

Once depletion was limited to 50 per cent of the income from *the property*, the definition of that term (the property) became of major significance. Because the term had been used in more than one way in the Regulations, the Revenue Service in 1941, and again in 1944, issued a memorandum defining *the property* as ". . . each separate interest owned by the taxpayer in each separate tract or parcel of land." However, so long as they were consistent, taxpayers were permitted to combine two or more mineral deposits found in a single tract of land and to treat this combination of interests as a single property. All interests in the tract not so combined had to be treated as separate properties.

In 1954 the Code was amended to permit one aggregation of properties within each "operating unit." These aggregation provisions, however, were revoked in 1964 for oil and gas producers, so that the Code now provides for the determination of "the property" in the computation of percentage depletion by substantially the same method as before 1954.

Source: Percentage Depletion: Economic Progress and National Securit
prepared by Special Task Force of Mid-Continent Oil & Gas Association, March, 1968.

**ARMSTRONG & McLEOD CO.**
P. O. BOX 819
OKMULGEE, OKLAHOMA 74447

April 25, 1983

COMMITTEE ON
RECEIVED
APR 29 1983
WAYS AND MEANS

Mr. John Salmon
Chief Counsel
Committee on Ways and Means
1102 Longworth Building
Washington, D. C. 20515

Dear Mr. Salmon:

A letter which I received today from Congressman Jim Jones of the 1st District of Oklahoma asked for some facts concerning "Risk" and "Realities" of the oil and gas business as well as the impact of tax provisions which distinguish between income received by independent producer and integrated companies, etc. I will address some of these questions at this time. For starters I would like to point out that in "Reality" three groups of producer exist:

1st, Integrated Companies (usually majors)
2nd, Large Independents
3rd, Small Independents

In a probable over simplification I will, in my opinion, distinguish the three from each other:

The Integrated Companies can, for the most part, take, or move, if you will, their profits and losses anywhere they wish.

The Large Independents often produce in excess of 1000 BOD (or its equivalent).

The Small Independent usually produce 200 BOD (or its equivalent) or less, and probably represent 95% or more of the total producers in America. Their wells produce an average of 3 BOD or less. There are several hundred thousand of these wells in the contiguous U.S.A.

For one reason or another the IRS has set a 1000 BOD (or its equivalent) as the difference between large and small. The 600 BOD in between is an interesting difference and not addressed by anyone.

Cash flow to integrated companies and large independents are of such magnitude that they move substantially and efficiently in the lobby areas of the Congress.

Can you tell me by any stretch of the imagination why a Windfall Profits Tax ever escaped the gas industry? I can only surmise the majors and large independents outspent everyone else for such a favored treatment and received it. Natural gas wells are, as a general rule, produced at a small percentage of the cost of a stripper oil well; i.e., 10 BOD or less. It is totally ridiculous to put a WPT on stripper wells of 10 BOD or less (actually, stripper wells average less than 3 BOD) while exempting gas wells.

There are several oil related organizations and none of them pull in the support of all three categories as they do not and can not have a true feeling for each other. Certainly the first two catagories have little, if any, feel for a small independent.

If the small independents could ever pull together, they too, could get favorable legislation and not what is left over.

If a small independent makes a profit from production they have to do it at the well head. This is grossly unfair as his market can be controlled by the majors and Multi Nationals as they can take their profit anywhere they wish, i.e., transportation, refining, exploitation, purchasing, exploration, marketing and brokering. The large independent slants his source of cash flow near the integrated companies market.

While a small independent, like myself, does not have the administrative cost of an integrated company or large independent, he has to do most everything himself or be able to.

Small independents usually must look to paying out his properties, and, hopefully, later on selling the same for capital gains and then starting over again while investing in something to furnish some degree of security in the future for him and his family with the proceeds.

Small independents usually must provide collateral on every loan for development with his (and his wife's) personal signatures.

The U.S.A. is one of the few countries in the world to have anti trust laws. If we are going to be such a nation, why in the world do we not use the anti trust laws, or, if not, strike them from the books and forget it?

I submit to you that integrated companies should not be integrated. They should be in only one of their lines integrated (or consolidated) and the other companies should be independent profit or loss centers which stand on their own merit. They should be precluded from a favorable relationship of any kind with their present parent or affiliate. This would require each segment; i.e., pipeline, drilling, transportation, refining, marketing and development of production to be very well managed or the attrition and agressive competition would terminate them from the market place.

I also submit that a Multi National situation should require strict government participation as stock holder and be represented on the board of directors.

The integrated companies (Majors, for the most part) are usually well managed, immensely wealthy and use their wealth as needed, when needed. They can take their profits and/or losses anywhere in the world that they wish.

What do you think a person should think when they read where the Chairman of the Board of 4 of the American original 7 Sisters met with Sheikh Yamani in Europe recently? Can you imagine what they talked about! Any anti trust action? I doubt it!

Do you wonder why or blame small independents when they sell out and start over several times?

am of the school that the major companies can do anything they wish.

isk' You can be assured there is plenty of risk for the small independent as e can be taken out by one stroke of the pen with adverse legislation or oil ricing changes; e.g., it was meant that once a stripper lease, always a stripper lease and now the IRS wants to change that and we must wait and see if the ongress is going to let them get away with it. We try to make long term plans; .e., 5, 10, 15, and 20 years and it is indeed thrilling as it is like sitting n a powder keg with someone else running around with the match.

t would seem to me that with inland refining apparently mandated, or destined o be obsolete, that it would be in tha government's best interest to take them ver at salvage value, fund the operation to make them viable and to train and mploy people that the government would otherwise have to support through welfare o run the company! When and if the economics improves, the government could ell half (split control) to an intrapreneur within an entrepreneur's group nd direct the value and proceeds of the government half to be permenantly and erpetually designated to Social Security support. Research and development of obotics and high technology could also be partially funded by the U.S.A. for tock and equity; again, with any and all proceeds designated to fund the group hat the robotics and technology replace; i.e., ear mark the receipts for Social ecurity. Enough of these companies could fund Social Security. While you're t it, the royalty received from federal leases should go to fund Social Security. t could quite well cover the cost. An import duty of $8.00 per bbl for crude nd more for refined products (cover the differential and cost) could facilitate his. Give it some thought!

y name is: Clyde Joseph Holman, age 52
I am: President of Armstrong and McLeod Company
and Holman Exploration, Inc.
Phone: 918-756-5772

rmstrong and McLeod Co. (a small independent production company) was acquired y me in 1978 and will be a half century old in 1984. Armstrong and McLeod is n operating subsidiary of Holman Exploration, Inc. I personally have been in he oil and gas business since 1950.

hank you for your time, as it is difficult to be brief with such a subject matter.

Very truly yours,

Clyde Joe Holman

Clyde Joe Holman

kh

c: Jim Jones, M.C.
Claude Pepper, M.C.

1522 Grantbrook Lane
Dallas, Texas 75228
May 6, 1983

Rep. Dan Rostenkowski
Chairman of the House Ways and Means Committee
U. S. House of Representatives
Washington, D. C.

COMMITTEE ON
RECEIVED
MAY 10 1983
WAYS AND MEANS

Dear Mr. Rostenkowski:

I urge you to lend your support to eliminating percentage for not only oil and gas but for all minerals. I'm a CPA and worked in oil and gas taxation for over 15 years, and I can state with authority that as far as I know percentage depletion is the only tax law which permits a recovery in excess of cost. It's purely and simply a government sudsidy. And it is outrageously wrong in regard to royalty owners because royalty owners don't risk anything in drilling and producing.

Percentage has for all practical purposes been replealed as far as major operators are concerned. They still get percentage on fixed contract gas; and percentage depletion should also eliminated for this gas. In other words, percentage depletion should be eliminated entirely. Period!

And while you're studying other loooholes, why don't you support closing all loopholes?

Sincerely,

Milton Braun

Milton A. Braun

# Statement of The Christian Science Church on the Windfall Profits Tax

When Congress enacted the Crude Oil Windfall Profits Tax ct, it exempted from the tax oil production by a charitable ducational institution or a charitable medical facility, if eld on January 21, 1980 (26 U.S. Code sec. 4994(b)). Intersts held by a church on that date were exempted only to the xtent they were dedicated to the support of a medical facility r an educational institution. This limitation reflects a esire not to exempt religious organizations as such, while xempting schools and hospitals.

We find such a policy difficult to understand. Tradiionally, churches have been the last institutions taxed ecause of their uniquely special status in American life, ecause of the potential for entanglement between church and tate implicit in any tax, and because their funds are put o a use which enjoys broad support among the American people.

The Economic Recovery Tax Act of 1981 (P.L. 97-34, sec. 604) lso exempted from the tax residential child care agencies.

We have checked informally among the major denominations epresented in Washington and find none which is aware of any nterests in oil production owned by its churches. The hristian Science Church does hold such an interest, the result f a bequest received before the enactment of the windfall profts tax.

It seems anomalous to exempt schools and hospitals from his tax but not churches, particularly since the revenue oss involved is slight. We are asking the Ways and Means ommittee to amend 26 U.S. Code, section 4994(b) to include n the definition of "qualified charitable interest" organiations described in section 170(b)(1)(A)(i) of the Internal evenue Code. This change would restore the balance among ecognized categories of public charities and would acknowedge the importance of governmental restraint in taxing eligious organizations.

# STATEMENT FOR THE
# SUBCOMMITTEE ON OVERSIGHT
# COMMITTEE ON WAYS AND MEANS
# U.S. HOUSE OF REPRESENTATIVES

## HEARINGS ON THE TAX TREATMENT OF PRODUCERS OF OIL AND GAS ON MAY 5-6, 1983

by
Frank E. Cotton, Jr.
Professor and Department Head
Department of Industrial Engineering
Mississippi State University

I am pleased to be invited by you to make a statement on the tax treatment of oil and gas. Since my statement relies heavily on my background, I will note a few relevant biographical items.

My specialization is engineering economic analysis, which I have applied, researched, and taught for over 35 years. After my release from the U.S. Navy at the end of World War II, where I had been serving as a radar systems officer, I worked over a decade with two major industries, most of which was with a major petroleum firm. Since then, I have been with the University in my home state.

With the petroleum company, I made studies and recommendations for top management, using economics, petroleum economics, and engineering economic analysis (my Ph.D. degree was in Economics). While with the Company, I developed and implemented the first modern system of profitability analysis of petroleum exploration and development prospects ever to be used in the petroleum industry. That was in 1951, and the system is used throughout the petroleum industry today.

Since being with the University, I have worked with NASA, research organizations, and many types of industrial firms. Various professional responsibilities, including presidency of the Institute of Industrial Engineers, have involved me with practicing engineers and managers in a wide range of other firms. I am a member of the IPAA Cost Study Committee and their Statistical Subcommittee and Cost of Finding and Developing Subcommittee, and am doing research in the area of petroleum costs.

My statement is in abbreviated format. However, should you desire further details, I will be pleased to provide them.

## 1. SUMMARY AND CONCLUSIONS

The following summary points and conclusions are derived from this statement and supporting information and analyses.

1.1. Domestic petroleum supplies are substantially lower than they would be if it were not for the: (1) reduced/eliminated percentage depletion allowance and imposed minimum taxes; (2) limitations in expensing intangible drilling costs and imposed minimum taxes; (3)

imposition of "windfall profits" taxes; and (4) elimination of capital gains treatment of production revenues.

1.2. The three tax incentives stimulated petroleum investments which substantially exceeded the direct tax losses. They stimulated a domestic petroleum supply sufficiency that was strategic to the nation's economy and security over several decades.

1.3. The three tax incentives produced net tax gains, not losses, in total Federal revenues. Reduction/elimination of these tax incentives produced net tax losses in total Federal revenues. This takes into account: (1) transfer of income, jobs, and taxes to foreign countries through dollars spent on imports that would have been spent on higher domestic production; (2) multiplier effects of the tax incentives in attracting more funds into petroleum investment than the amount of tax benefits; and (3) tax revenues from all sources due to the stimulated flow and turnover of investment outlays, resulting production revenues, and reinvestments from these generated funds.

1.4. Further reductions in the favorable tax treatments of independent producers or of integrated firms would reduce domestic petroleum investment and supplies, federal and state taxes, national income, and jobs. This would cause higher petroleum imports and larger trade deficits.

1.5. Increases in the above favorable tax treatments and elimination of the WPT would increase domestic petroleum investment and supplies, federal and state taxes, national income, and jobs. Petroleum imports and trade deficits would decline below what they would have been.

1.6. Differences in independents and majors (integrated petroleum firms) justify special tax treatments of independents. Independents serve a strategic role in the nation's petroleum supply, and this role would be severely damaged by further reductions in the favorable tax treatments. Increases in these favorable tax teatments to independents and to majors would be beneficial to the nation's economic welfare and security.

## 2. RELEVANT ECONOMICS OF THE INDUSTRY

Agriculture, manufacturing, and extraction industries are different from each other. Furthermore, petroleum exploration and production is vastly different from other extraction as well as from other industries. Historically, tax policy has recognized these differences through tax treatment. These unique economic characteristics of petroleum exploration and production include:

2.1. Continuous flow of huge investment expenditures is essential. The short life of most wells requires continuous reinvestment of increasing amounts of capital for new exploration and drilling just to stay in business.

2.2. Very high risks plague the industry. The probability of losing the total investment in a drilling venture can be 50% to 90% and higher. The chance of being bankrupt from a series of costly dry holes faces all operators.

2.3. Investment is mostly in intangibles, such as leasing, exploring, and drilling, which have no tangible value. Wells may go dry, cave in, or become uneconomic at any time--largely unpredictable.

2.4. The industry is fiercely competitive. Inadequate information (at best) and different interpretations of information intensify expectation of success based on independent judgment. The failure rate is high--an inherent characteristic of the oil production business.

2.5. Oil prices are low; they appear high due to events in the last decade. Before World War II, oil prices were suppressed by ample supply and intensive price competition within the industry. Since World War II and until recently, oil prices were suppressed by high surpluses of low-cost foreign oil flowing into domestic markets. Long-term trends show that oil prices have not increased more than prices of other commodities and services. Only the time-frame of these increases has been different due to prices having been suppressed so long. Comparative examples: price inflation of bread, medical fees, postal rates and services, and cars. Even today, distilled water costs more than gasoline and heating oils, including all petroleum taxes.

2.6. Natural gas prices are low; long-suppressed prices and recent developments make them appear otherwise. Historically, natural gas has been largely a by-product of crude oil production. Lack of adequate pipelines created give-away prices. Then regulation continued those prices at a fraction of energy equivalency of oil products. As markets for cheap gas expanded, regulation prevented prices from rising to provide incentive to drill for gas. This led to widespread shortages of natural gas and chaotic market results. Natural gas prices in recent contracts and in most old contracts are far below their energy equivalency of No. 2 heating oil, which is the logical basis for competitive price comparison.

2.7. Domestic crude oil prices are based on international oil prices. Natural gas prices, if determined by the free market, are established and controlled by other competitive fuels. Plentiful domestic natural gas reservoirs provide opportunity for supplementing domestic deficiencies of petroleum liquids by converting natural gas into methyl alcohol for gasohol and into other high-value liquids and chemicals. Integrated firms can develop and benefit from these opportunities. Independents can only sell their gas at marginal market prices to the majors, refiners, and pipelines.

2.8. Domestic oil supplies in the 1930's were adequate. Important incentives that stimulated drilling to produce this adequacy were the 27.5% depletion allowance, expensing of intangible drilling costs, and capital gains treatment of oil produced. This adequacy of domestic oil supply was a strategic necessity to the nation's military strength and successes in World War II.

2.9. Since World War II, three principal factors have caused the rising gap between domestic demand and domestic supply of oil: (1) competition of cheap foreign oil suppressed domestic oil prices; (2) diminishing shallow oil and low-cost reservoirs caused higher risks and escalating investment costs to find, drill,and produce crude oil; and (3) elimination or reduction of favorable tax treatments combined with implementation and escalation of severance and other taxes converted a net favorable tax incentive into a net unfavorable tax burden. The industry has been squeezed by suppressed prices, escalating costs, and a turnaround from tax incentives to tax disincentives. A major deficiency of domestic oil supply has been the result; the supply adequacy of the 1930's and 1940's no longer exists. It has been production capacity, not unproven reserves, that has served the nation's domestic needs--in times of peace and war.

## 3. INDEPENDENTS AND MAJORS

The independents and the majors (integrated oil firms) complement each other; they need each other, and they serve somewhat different purposes in the industry. All of the producing organizations must face the industry characteristics noted above. However, as can be shown by the mathematics of probability and by historical petroleum markets, large size and vertical integration into the markets do reduce risks and increase the assurance of adequacy and stability of profits.

Independents and majors continuously face high risks, high costs, and high tax burdens at the producing end. Independents, in addition, are confronted with the vicissitudes of the market in their selling their crude oil and natural gas with little or no control over prices or market availability.

Some other characteristics that usually distinguish independents from majors are listed below.

3.1. In general, independents take higher degrees of risk than do majors. They go more into unproven areas, drilling 80-90% of the exploratory wells, and discover most of the major oil fields. Consequently, they drill a higher percentage of dry holes, losing their total investment in the venture. Majors benefit from this drilling, as their leases cover the majority of the acreage, so the results of independent wildcatting help majors determine which of their acreage is most profitable to develop. Majors often farm out a piece of an acreage to an independent to drill. If it is dry, the independent loses his investment. If it is a producer, the major takes a high percentage of the production. Either way, the major learns more about his acreage--whether he should develop the larger acreage or not. The independent risks his drilling investment, but from it they both may gain. The majors also may buy producing oil and gas wells from independents; in some cases, they purchase independent firms. These factors contribute to the statistics that although independents drill most of the exploratory wells, the majors produce most of the oil and gas.

3.2. On the average, majors drill more costly wells than do the independents. Thus, the amount of investment they have at risk in a venture averages higher. Most independents cannot afford to risk so much capital in a single venture. Consequently, most of the off-shore and Alaskan wells are drilled by majors. The risk of going broke decreases as the size of the financial resources of the firm increases. Consequently, majors can afford the risk of more costly ventures that could bankrupt most independents. Nevertheless, majors must produce a competitive net profit. To do this, much of their drilling is allocated to acreage having computed potential of very large reservoirs, large production, and large revenues. The huge investment costs limit these opportunities to the major firms with large capital resources. The independents drill the lower cost, smaller potential acreage. Occasionally, they, too, find a really good producer; this is the attraction that motivates them to invest in such high-risk ventures. Usually, their drilling results in dry holes or marginal producers. There are millions of small-to-middle size oil and gas reservoirs in the United States. They are elusive and costly to find. Tax treatments can baffle or enhance incentives to expend the resources to find and produce these reservoirs.

3.3. Most independents must attract a large part of their investment capital from private investors; without these funds, most independents would have to go out of business. Because of their high risk and limited resources, independents don't have the access to venture capital from banks and other lending institutions that is more available to the integrated majors. Availability of funds from private investors is heavily determined by tax treatment. Favorable tax treatment acts as a catalyst, attracting a flow of investment funds much larger than the tax differential. This multiplier effect is due to merging of high risk and high potential, even though the average returns may be marginal or negative. It should be noted that this multiplier effect, which produces a high cost effectiveness of tax incentives, affects the level of investment in exploration and drilling of both independents and majors.

3.4. Because the independents focus mostly on high risk, small reservoirs that are not sufficiently attractive to majors, they provide an extra margin of proven reserves, production, and domestic energy sufficiency that otherwise would not be available. The exploration, development, and production activity to achieve these results also provide domestic income and jobs which otherwise would be produced overseas at the expense of American import dollars.

3.5. A very high percentage of independent production is stripper production. This is high cost production, much of which would be sub-marginal for majors. Maintaining financial viability of stripper wells provides an additional margin of producible reserves, production, and domestic energy sufficiency.

## 4. ECONOMIC REALITIES AND FISCAL POLICY

Many decades of petroleum history document unique features and problems of the industry and how it responds to various stimuli, such as tax treatment, market conditions, and changes in prices and costs. Oil and gas are strategic to the nation's economy and security. The gap between our needs and our domestic supplies must be imported. Our ability to assure imports is less dependable than for domestic development and production. Furthermore, importation of petroleum is an export of currency, income, and jobs to foreign countries. It is not a shift of funds from one domestic industry to another. Instead, it is a flow of the funds overseas, producing income and jobs in a few foreign countries, many of which are unstable and undependable. Other considerations that are relevant to the tax treatment of domestic oil and gas production include the following:

4.1. Economic theory is unproven economic hypothesis. There are many conflicting economic theories, none of which is proven. Economic realities are manifestations of economic history which are tested and retested by actions and reactions over decades of experience. Consequently, economic realities provide a more dependable basis for developing fiscal policy concerning the petroleum industry.

4.2. Appropriate fiscal policy, presumably, implies that it is effective in serving national needs and is consistent with the nation's economic system. If fiscal policy regarding the petroleum industry is to be sound and effective, it needs to take into effect three vital considerations: (1) the special economic and security needs of the nation relevant to petroleum; (2) the important unique characteristics of the petroleum industry; and (3) the time-tested realities of the nation's petroleum economic history. This nation has always encompassed such considerations in its fiscal policies; to do otherwise could jeopardize the economic welfare and national security. Just a few such examples are: tariffs, tax credits, accelerated depreciation (very effective in World War II), direct subsidies, price supports, land banks, tax treatments, energy credits, and research grants.

## 5. TAX TREATMENT CONSIDERATIONS

The strategic role that petroleum serves in the nation's economy and security makes it essential that a healthy domestic petroleum industry is assured and that it is capable of producing sufficient domestic crude oil and natural gas to accommodate the economic well-being and security of the country. Several factors deserve special consideration.

5.1. Petroleum needs not developed domestically must be imported from foreign sources. Dollars used to purchase petroleum outside this country have a multiplier effect on national income, taxes, jobs, and other economic impact factors in the exporting countries. Those dollars, if spent on purchasing domestic petroleum, would, instead, have those direct and indirect multiplier benefits in this country. The domestic production capabilities must be available if those dollars are not to be exported, along with their multiplier benefits. To provide these production capabilities, incentives to invest in domestic exploration and development must be sufficient to attract the necessary investment resources. Expensing of intangibles and depreciating tangibles over a short period also can increase investment turnover, thus increasing the investment effectiveness of available investment funds--without reduction in taxes, only timing of tax flow.

5.2. Funds not invested in domestic petroleum are not necessarily invested in other domestic enterprises. The investment market is worldwide, with many options available to the investor. In addition, there are many other alternatives available for allocation of available funds, many of which have no beneficial impact on the American economy. Consequently, favorable tax treatment of the domestic petroleum industry is more likely to have positive economic effect on American business and industry through direct and indirect impact of increased petroleum investment than it is to have negative impact by reducing investment funds available to other firms. The free world is an open economic system with a multiplicity of investment opportunities.

5.3. Statements of tax changes from modifying a favorable tax treatment are often misleading in that they represent only the anticipated changes in that specific tax and even for the specific year or period. Estimating the impact of the tax change on other taxes, directly and indirectly, is essential to forecasting the anticipated total net impact on federal tax revenues. For example, a reduction in the depletion allowance would directly increase income taxes (reduced depletion allowance partly offset by income taxes on the reduced allowance) of those petroleum-firms and investors affected. However, the reduced depletion allowance would reduce the incentive to invest, probably by much more than the amount of the depletion allowance reduction. The reduced investment would result in fewer jobs, reduced taxes at all levels of the economy, and fewer productive domestic wells to produce a stream of income, taxes, and jobs over the future years the petroleum would have flowed. Furthermore, in estimating tax impact, time-shift in tax collections should be distinguished from tax reductions. This relates to matters like expensing intangible drilling costs and delays in payment of "windfall profits" taxes, wherein taxes are delayed but not reduced.

5.4. Percentage depletion has, for decades, been common in the extraction industries and in the timber industry. Petroleum exploration and development was stimulated for decades by a depletion allowance of 27.5%. During this period, the depletion allowance contributed significantly to maintaining the sufficiency of domestic petroleum reserves and supplies. Then the petroleum industry was singled out for elimination of percentage depletion except for limited applicability to non-integrated producers. This has diminished the incentive to explore and drill, resulting in a lower level of domestic petroleum reserves and production than would have been the case. Percentage depletion allowance is a powerful catalyst in stimulating exploration and drilling. Consideration to increasing and reinstating this allowance should be given, along with eliminating the minimum tax limits that reduce its effectiveness.

5.5. Expensing of intangible drilling costs increases the turnover of investment capital. It delays, but does not reduce, some taxes. The net effect is increased federal taxes due to the impact of increased investment in exploration and drilling. Elimination of IDC's would severely reduce availability of investment capital and would result in a decline in domestic exploration and drilling. Requiring depreciation of any intangible costs over the anticipated productive life of the reserves is counterproductive. Consequently, expensing of all intangible exploration and development costs, including intangible drilling costs, should be permitted, with the option of capitalizing part of all and using ACRS. The minimum tax applied to IDC's reduces their application and effectiveness; consideration should be given to eliminating this limitation.

5.6. The "windfall profits" tax imposes an extraordinary tax burden on the petroleum industry. It does not adequately consider the escalation of costs associated with exploration, development, and production. It also does not consider the fact that crude oil prices are not out of line on the high side; they have risen to be in line with long-term price increases of other products and services, as illustrated earlier. Yet, other industries and services have not had such taxes imposed on them. This tax is a disincentive to investment in petroleum exploration and production. Its rapid phase-out would be cost effective and beneficial to the nation. Consequently, it should be phased out as quickly as possible. However, the reduced tax level for independents is justified and should be retained until the tax is eliminated.

5.7. Until recent years, the capital gains tax rate was applicable to petroleum revenues. This was in recognition of the fact that the oil and gas reserves represent the invested capital and that production of those reserves is production and depletion of the capital. Intangible costs incurred in leasing, exploration, and drilling are necessary to find and reach the petroleum reserves, but are worthless otherwise. Changes in the tax laws eliminated application of capital gains tax rates unless all interest in the property is sold. Yet, capital gains can be applied to any quantities of timber, coal and land, and it can be applied to cows, horses, and many other assets. Reinstatement of this application of the capital gains tax, as is available to timber, coal, and land, should be strongly considered. It would be a cost effective stimulus to domestic exploration and production.

5.8. During recent years, three major tax stimuli to investment in domestic exploration and development of petroleum reserves have been eliminated or reduced. In addition, a "windfall profits" tax has been imposed. Costs have escalated. These factors have contributed significantly to the large deficiency in domestic petroleum reserves and production. The investment incentives are highly cost effective, and the resulting investments and total investment impact return more taxes than the tax cost of the incentives. Furthermore, the flow of stimulated investment enhances the nation's economy and security with additional domestic income, jobs, taxes, and petroleum. There is justification for special tax incentives for the independents, especially if any of the favorable tax treatments are not retained as they existed before they were reduced or eliminated. However, both cost effectiveness and impact benefits to the nation support eliminating the WPT and reinstating these favorable tax treatments in full to all exploration and development of domestic crude oil and natural gas.

# STATEMENT
# SUBMITTED TO THE
# SUBCOMMITTEE ON OVERSIGHT
# COMMITTEE ON WAYS AND MEANS
# U. S. HOUSE OF REPRESENTATIVES
# THE HONORABLE CHARLES B. RANGEL, CHAIRMAN

by

RONALD L. DRAKE
ATTORNEY AT LAW
1101 14TH ST., N.W.
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WASHINGTON, D. C. 20005
(202) 682-0223

MAY 27, 1983

MR. CHAIRMAN:

My testimony addresses the unforeseen and largely undisclosed effects of the current exemption of stripper oil from the Crude Oil Windfall Profit Tax now allowed to independent oil producers.

This preferential tax treatment of independent oil producers adversely impacts the property rights of landowners in old fields that are now producing stripper oil from existing wells or from newly drilled wells, both of which are continued or placed into production only as a result of the combined effects of the high price of oil and the preferential tax exemption. My own family's experience is illustrative of the problem.

The Fairbanks Oil Field, located in Sullivan County, Indiana was discovered and placed into production in 1950. Farmers leased their farms to the Carter Oil Company in return for small cash payments, and the promise that the landowner would receive the proceeds from one-eighth of the oil production. Most farmers, uninformed and unprotected, then sold one-half of their remaining interest to royalty buyers who arrived immediately upon the execution of the lease. Farmers had little knowledge of the extent or potential value of the strike, and less knowledge about their rights.

The leases were standard forms prepared by the oil company and granted to the oil company the exclusive right to drill and produce from the leased land for a term of three years and as long thereafter as oil is produced from the premises. The oil companies represented that Indiana law allowed them to drill no more than one well on each twenty acres, and that they were thus limited to exploiting only that amount of oil that could be removed by any one oil well drilled or produced on each twenty acres. Any oil remaining after production of that one well ceased would remain the property of the landowner to be exploited or not as he wished, with no further rights therein by the oil company.

The Fairbanks Oil Field was drilled and placed into production with each well located on at least twenty acres, as required by the spacing regulations of the Indiana Natural Resources Commission. In 1969 the Carter Oil Company sold its interests in the field to independent producers, who continued pumping the field without incident or objection until 1978. During that period the producers shut down wells in the normal course of events as production fell below the profit line. This was compatible with what had been anticipated as normal procedure by both the oil company and the landowners at the time the leases were executed in 1950.

By 1978, however, the price of crude oil had escalated so dramatically, creating an unearned windfall for the producers, as a result of the Arab oil embargo, that it became profitable for the independent producer to retain marginal wells in production as strippers, long after the normal time for abandonment. This then continued the lease in effect and delayed the return of control of the land to the landowner for his own exploitation of the remaining oil not reached by the one well on twenty acres. Further, it then became profitable for the independent oil producer to drill additional wells, placed at a spacing of one well per ten acres, even though this was never contemplated when the leases were signed. The exemption from the windfall profit tax simply exacerbates the problem, and continues to make it profitable for the independent oil producer to drill new wells, in violation of the intent of the leases.

Landowners in Indiana have objected to this practice, which requires a special exception from existing regulations to be granted in each case by the Indiana Natural Resources Commission. The Commission has been unsympathetic to those objections, and the issue is pending before the Indiana Court of Appeals.

The preferential tax treatment of independent producers has the practical effect of diminishing and altering the property rights of landowners, to the benefit of oil producers. It aids in the transfer from the landowner to the oil producer of rights not bargained for nor contemplated at the time the oil leases were executed more than thirty years ago.

The governmental agency in Indiana empowered to halt this practice has indicated through its decisions that it will provide no protection to the farmers and other landowners from the unfair advantage being taken by the independent producers. This places the landowner in the anomalous position of seeing his constitutionally protected property rights transferred to the oil producer with the approval of the Indiana Natural Resources Commission, indirectly resulting in part from the preferential tax treatment. Certainly, neither this committee nor the Congress anticipated or intended this inequitable result.

To correct this injustice and still promote the unimpeded exploration for domestic oil, I urge that the Act be amended to require that in order for the independent oil producer to qualify for the exemption, he must submit a sworn certification that any new oil well drilled pursuant to a special exception from existing regulation has been specifically agreed to in writing by the landowner.

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1717 - 28th Street
Phone 327-4811

**Ferguson & Bosworth**
Independent Oil & Gas Producers
Bakersfield, California 93303

February 25, 1983

RECEIVED
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WAYS AND MEANS

The Honorable Dan Rostenkowski
Chairman, House Ways and Means Committee
2111 Rayburn House Office Building
Washington, D. C. 20515

Dear Congressman Rostenkowski:

I understand that hearings are to be held on taxation of independent oil and gas producers. Although I will be unable to attend those hearings or to give direct testimony, I hope this letter can be used in lieu of direct testimony.

The so-called "tax breaks" for independents were the result of a careful review of the various problems encountered by independents as compared to those of the fully integrated oil producers. The fact that independents sell no refined products to the consuming public set us apart from the integrated companies. Integrated companies, because they do sell refined products to the consuming public, are able to pass all expenses including taxes along to the public in the form of higher prices. Obviously, independents do not enjoy this privilege. For independents any increase in taxes must be obtained at the expense of their drilling budgets.

Since independents historically have drilled on the average some 85 to 90% of all the exploratory wells drilled domestically, any increase in taxes through the elimination of the considerations given them by past congressional conclusions will greatly affect the future of the domestic supply. Rather obviously, in the long run, such a move on the part of the present Congress would defeat its own purpose of raising added revenue.

The House Ways and Means Committee is surely aware that there has been a substantial drop in the price of world crude with further drastic cuts yet to come. I am also fully aware that this will mean a reduction in revenue to the Federal Government. Rather than whip a sick horse to death, why not do something to stimulate that horse and get him back on his feet.

For the benefit of the domestic industry and for the benefit of the U. S. Treasury, why not impose an import duty equivalent to the amount of decline in the price of imported oil. In addition to the direct revenue generated for the treasury, it would tend to stabilize the revenue generated from the Windfall Profits Tax. Rather obviously, the price of domestic crude would remain close to the price of imported oil plus the import duty. Such an action would stimulate further domestic drilling, thus helping to increase our reserves to ultimately become self sufficient, or nearly so. By the same token, it would help stimulate our economy and place many back on the payroll.

Make positive moves that will be more lasting. Negative moves will lead to shortages and higher rates of unemployment. Overtaxation of a particular industry has never helped anyone. Taxation that is equitably distributed is far less detrimental.

I would therefore urge the Ways and Means Committee to maintain a status quo on present taxes for the simple reason it will be more beneficial to all concerned in the long run.

Yours sincerely,

FERGUSON & BOSWORTH

Glenn C. Ferguson
Glenn C. Ferguson

GCF/kmt

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Ways and Means
Subcommittee on Oversight

May 2, 1983

The Honorable Charles B. Rangel, Chairman
Subcommittee on Oversight
Committee on Ways and Means
1101 Longworth House Office Building
Washington, D.C. 20515

Re: Tax Treatment of Producers of Oil and Gas

Dear Mr. Rangel:

The Subcommittee's review is to focus on the differences in tax treatment between integrated oil companies and independent producers. The differences are primarily between "Big Oil" and small business. In the capital-intensive independent oil and gas industry, the ability to attract investment capital is vital. This has been doubly true during the recent decade of frenzied growth in domestic drilling for oil and gas.

The Committee and Congress must appreciate that capital turns over especially fast in the drilling and production part of the industry. Much capital is dissipated in the acquisition of unproductive acreage and the drilling of dry holes or "dribblers". That portion of capital which is successfully employed must be recovered entirely out of the proceeds of rapidly depleting reservoirs.

Because these reservoirs are rapidly exhausted, capital must be constantly infused to find replacement sources. In the recent decade of both inflation and expansion the need for capital has grown geometrically.

Fortunately, the independent industry has been able to appeal to a broad spectrum of potential investors with widely varying objectives. Much of that diversity of appeal has been due to "different tax treatment for different types of oil and gas producers". The differences are primarily between "Big Oil" and small business.

As the tax aspects of oil and gas investments become less distinguishable from the tax aspects of investments in other industries, the base of potential investors will narrow. An attempt to place the independent oil and gas industry in that position just as our economy starts to expand would be exceptionally poor public policy.

The Administration and the Congress have noted the improvement in the economic cycle, the stock market is up and the business outlook is optimistic. Along with that improvement and business pick-up will come a fierce competition for capital, not experienced in the last several years of depression and recession. Along with an expanding U.S. economy there must be a dependable supply of domestic oil and gas, and the independent oil and gas industry must be able to attract enough capital to replace the continuously exhausting supplies.

The differences in tax treatment which currently exist are important ingredients in the ability of the independent oil and gas industry to attract the necessary capital. In addition, the tax differences enable thousands of small businesses to compete with the largest industrial "Big Oil" corporations in the world.

All the items in the Committee on Ways and Means Subcommittee on Oversight Notice of January 18, 1983 are distinctions between big and small business units of the industry. Without these tax differences, many of the small competitors will perish and the industry will become more concentrated. Independents traditionally have had the one tool--these tax differences--to attract venture capital necessary for exploration, wildcatting that has enabled them to discover and produce much of the domestic oil and gas.

Conventional wisdom would lead one to conclude that this incentive is unquestionably necessary if this nation is serious about energy self-sufficiency and independence.

It would be ironic if Congressional actions were to create in the mid-1980's the very concentration of the oil and gas industry it feared and railed against in the mid-1970's. Disqualifying an independent oil and gas producer from the listed tax differences would unquestionably pave the way for a monopoly in domestic oil and gas production.

Having stressed the importance of the listed tax differences to the continued health of the domestic oil and gas industry is not to endorse each and every one of them. The minimum tax imposed on intangible drilling costs is one notable example of a tax distinction which is really counter-productive.

Sincerely,

Elmer L Hoehn

Elmer L. Hoehn

ELH/hvy

The Manhattan Group

OIL AND GAS CONSULTANTS

DONALD F. X. FINN
MANAGING DIRECTOR

P. O. BOX 1823
NATCHEZ, MISSISSIPPI 39120
TELEPHONE 601/446 7355

March 1, 1983

COMMITTEE ON
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MAR 10 1982
WAYS AND MEANS

Oversight Subcommittee
Ways and Means Committee
U. S. House of Representatives
Washington, D. C. 20515

Gentlemen:

The annoucement of your plans to conduct an "inquiry into the special tax breaks received by the independent oil industry" prompts us to offer the following comments for your comsideration:

1. The oil and gas industry in Mississippi pays in tax dollars twice as much as any other industry in the State.

2. More than 51% of the oil and gas industry's pretax income goes to pay Federal windfall profit and income taxes versus 26% for other indsutries.

3. The oil and gas industry alone will pay 20% of newly enacted increases in Mississippi sales and income taxes.

4. In 1982 oil and gas drilling funds raised 54% less money nationally than in 1981. By being able to offer investors tax incentives (depletion, IDC's, ITC's) in exchange for their risk investment dollars, independents have been able to raise off-balance sheet financing for exploration. But because of decreased demand, declining prices, and heavy tax burdens, the economics of oil and gas exploration are no longer attractive to the investing public. If the Congress means to support domestic exploration, rather than adding to the tax burdens of the independants, it should seriously consider clarifying the right to currently treat geological and geophysical exploration expenses as current business deductions. Frank Burke, Current Expensing of Geological and Geophysical Costs, 34 Oklahoma Law Review 778 - 789 (1981). This is also true for the geothermal industry which very much needs tax incentives if it is going to contribute significantly to our domestic energy reserves.

5. Unless you are aware of the risks investors have to take you cannot judge the need for tax incentives. Take Mississippi. Beytween 1930 and 1982, 635 oil and gas fields were discovered in the State which contained over 1,800 separate reservoirs. Over 85% of those fields are still producing in 1983. But it took the drilling of 20,514 holes to establish these fields, and of these only 39% became wells, the other 61% were dry. Investors simply could not afford to take such risks unless they had tax incentives permitting them to partially offset them. In 1980, 674 holes were drilled in Mississippi. 63% were dry. In 1981, 758 holes were drilled, 65% were dry. These are the stark facts you must take account of.

Sincerely yours,

Donald F. X. Finn

COMMITTEE ON
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APR 21 1983
WAYS AND MEANS

THE
MANHATTAN
GROUP
OIL AND GAS CONSULTANTS

DONALD F. X. FINN
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April 18, 1983

Hearings on the Tax Treatment of Producers of Oil and Gas
Subcommittee on Oversight, Committee on Ways and Means
U. S. House of Representatives
Washington, D. C. 20515

Gentlemen:

As you consider "the effects of differences in the tax treatment of various types of oil and gas producers", may we direct your attention to some facts cocnerning the current depressed state of the oil and gas industry:

1. More than 50% of domestic drilling and workover rigs are idle because of depressed demand for hydrocarbons and a decline in oil and gas company earnings. More than 800 rigs were stacked during the 1Q of 1983.
2. We expect that total well completions in 1983 will be about 65-66,000, down at least 12% from 1982. We expect only a modest increase in well completions beginning with the 4Q of 1983 or the 1Q of 1984. Oil well completions will fall about 6-7%, gas well completions will fall 24-25% this year.
3. We expect that consumption of tubular goods will decline from 5,700 thousand tons in 1981 to 3,500 in 1983 and 4,100 in 1984.
4. Well permit applications in 14 leading oil and gas producing States has fallen 36% from December 1982 (4,219) to March 1, 1983 (4,219). The largest drops were in Oklahoma, Kansas, Louisiana and California.
5. We expect to see a 23% decrease this year in Seismic Land Crew Counts (from 532 in 1982 to 410 in 1983).
6. The 18 largest (in terms of gross revenues) oil and gas exploration and production companies earned about $15.8 billion in 1982. This represented a return on investment (assets plus long-term debt) of about 7 - 8%. AT&T realized an ROI of 12.2% and IBM realized an ROI of 33.5%.

The independent oil and gas exploration and production companies have found over 70% of new gas supplies. They are principally dependent on off-balance sheet financing via Drilling or Exploration Programs through which they can attract risk investment dollars by passing through tax incentives (depletion, IDC's and LTC's) to investors. Unless they can continue to offer investors such tax incentives, independent exploration activities will be vastly reduced.

Sincerely yours,

Donald F. X. Finn

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April 23, 198

Subcommittee On Oversight
House Committee On Ways and Means
U. S. House of Representatives
1102 Longworth H.O.B.
Washington, D. C. 20515

COMMITTEE ON
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WAYS AND MEANS

Attention: John J. Salmon, Esq., Chief Counsel

Gentlemen:

Responding to your notice dated April 18, 1983 announcing hearings on the tax treatment of producers of oil and gas which will review the effects of differences in the tax treatment of various types of oil and gas producers, we submit the following comments for your consideration:

Intergal to the operation of both major and independent oil and gas exploration companies is the development of domestic geothermal energy resources.

Commercial electric generation at a geothermal power plant first began in 1960 in Sonoma County, California with PG&E's installation of an initial 12.5 MW unit. By May 1983 1,128 MW will be online to be expanded to 1,733 MW by 1989. Steam is supplied by Union Oil Company, Natomas, Aminoil and GRI.

The Northern California Power Agency, with steam supplied by Shell Oil Company, has 110 MW of capacity at The Geysers Geothermal Field in Sonoma County.

A 10 MW demonstration plant at the Salton Sea in Southern California bodes well for the harnassing of the large geothermal resources known to exist in that harsh environment.

Sierra Pacific Power Company has announced that it will sponsor an initial 20 MW geothermal power plant in Nevada as soon as possible.

At Roosevelt Hot Springs, Utah, Phillips Petroleum Company and the Utah Power & Light Company are rapidly progressing with plans to begin commercial geothermal electric generation.

At the U. S. Navy Weapons Center, China Lake, California the California Energy Company and investing partners are working to install an initial 25 MW power plant in an area where the U.S.G.S. has estimated that possibly up to 4,000 MW of capacity may exist.

Other plans for developments in Oregon, Idaho and other western States are in various stages of progress. The attached memorandum is a very brief summary of the tax treatment of geothermal resource development and the serious problems connected with it.

Sincerely yours,

Donald F. X. Finn

Geothermal Energy Institute
P. O. Box 1623
Natchez, MS 39210
601-446-7355

April 23, 1982

MEMORANDUM RE: Geothermal Tax Incentives

1. Geothermal exploration in the United States was severely hampered for many years because Federal lands were not available for development. This was solved in part by the Federal Geothermal Leasing Act of 1970, but a statutory restriction which prohibits any one company from owning leases of more than 20,480 acres in any one State. Leasing regulations were not prepared and finalized until 1974 and since then (and as of 9/30/81) only some 1,633 leases covering 2.7 million acres have been issued on Federal lands.

An increase in per State restrictions should be made to 50,000 acres to encourage exploration on Federal lands.

2. Another deterent to geothermal exploration was the resistance of the U. S. Treasury Department to permitting geothermal explorers to deduct drilling costs or claim depletion. This was remedied to an extent by the Energy Tax Act of 1978 which, for the first time, permitted an investor to deduct as a current expense the costs of intangible drilling and development costs in the case of "geothermal deposits". The Act also provided for a 22% depletion allowance, which however, reduces to 15% beginning in 1984.

Since geothermal development is akin to uranium and coal development, and since first revenues do not begin (unlike oil and gas revenues) for 5 - 7 or more years after exploration begins, all upfront geothermal exploration and drilling costs should be permitted to be expensed on a current basis. Geothermal exploration costs are substantial and time-consuming and investors consider the lack of such treatment a substantial disincentive to investment in light of the fact that investment will not produce any revenues for several years after it is made nor will depletion income be realized until a geothermal facility is placed on-stream and produces revenues.

3. The extension of the at-risk rules to geothermal exploration and development by the Energy Act of 1978 has also resulted in erection of another institutional barrier to innovative financing programs. It should be repealed. Long-lead times to first revenues and to profitable operations are an inherent ingredient of geothermal exploration and development projects. Only tax incentives can overcome the resistance of investors to commit speculative risk dollars to such long-term projects.

4. The Energy Tax Act of 1978 also extended recapture rules to geothermal IDC's. In the case of integrated companies it appears that, unlike independent operators, the recapture rules not only extend to geothermal IDC's deducted currently, but also to the amortized portion of the15% of IDC's they are required to capitalize. This is but another disincentive discouraging geothermal exploration in the United States.

5. What limited experience the geothermal industry has gained since 1974 teaches that a commercial geothermal deposit may be located on Federal lands but for a whole variety of reasons it cannot be placed onstream for a number of years. In some cases, transmission lines have to built to an otherwise remote area, in other cases exisitng transmission lines do not have the capacity to carry the power which could be generated and new transmission capability is related to the ability of a local public utility to finance its operations. In yet other cases a whole host of legal and technical impediments prevent the rapid development of a field.

One encouragement that geothermal explorers need is comparable to the extension of offshore oil and gas lease terms. In the event that 10 years pass before a geothermal deposit can be commercailly exploited, a lease should not be automatically canceled as long negotiations between the geothermal developer and a utility or industry user continue in good faith or good faith financing plans are being formulated.

This would permit explorers to speculate in the evaluation of potentially commercial geothermal deposits without suffering a loss of investment in the event production could not be sold within the 10-year primary term of Federal leases.

6. Lastly, and perhaps most importantly for the power plant financiers and owners, the 15% energy tax credit which is due to expire in 1985 should be extended as soon as possible and for at least ten years. This is essential in view of the long-term term planning and negotiating which is inherent in electrical generating and transmission projects as well as geothermal exploration and development projects.

N.B. Federal geothermal leases have been issued for the following States:

Arizona
California
Colorado
Idaho
Nevada
New Mexico
Oregon
Utah
Virigina
Washington
Wyoming

**READING & BATES PETROLEUM CO.**

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Tulsa, Oklahoma 74103
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BILL M. BURKS
President

COMMITTEE ON
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WAYS AND MEANS

May 11, 1983

Mr. John Salmon
Chief Counsel
Committee on Ways and Means
1102 Longworth Building
Washington, D.C. 20515

Dear Mr. Salmon:

The current hearings on taxation of the petroleum industry being held by the House Ways and Means Subcommittee on Oversight are of critical importance to the nation as a whole and to the industry in particular. As you are aware, the petroleum industry is the most heavily taxed portion of the industrial complex yet the Congress seems to be intent on increasing the tax burden still further.

Although the proposal being considered will affect the entire industry, the effect will be greatest on the independent oil producers. The viability of this segment of the industry which drills more wells and produces more domestic oil than the integrated oil companies will be dealt a serious blow if these tax proposals become law.

The side effects of increasing the revenues by this means should be carefully weighed before action is taken. Certainly, unemployment will increase in an industry where there have already been reductions in force of up to 15% for some companies. Further reductions in drilling rig use, which is down 50% from 1982, will also continue. Financial collapse of more independent producers and drilling contractors will occur with the high probability that more banking failures, such as "Penn Square", will result. The loss of orders to the already depressed steel and manufacturing sectors for tubular goods and high dollar specialty items will be a direct result of decreased drilling activity. It is obvious that the ripple effect on the very fragile recovery from the current recession could be disastrous.

Furthermore, with loss of incentives for stripper production and exploration/production drilling, a significant portion of current and future domestic production would be lost. Of course, this would be made up with imported crude, thus making this country even more dependent on OPEC.

In summary, the proposed changes to the existing tax structure would have far reaching detrimental effects, not only on the industry but on the nation as a whole.

Sincerely,

Bill M. Burks

BMB/vlh

**Shell Oil Company**

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May 27, 1983

Subcommittee on Oversight
Committee on Ways and Means
U.S. House of Representatives
1101 Longworth House Office Building
Washington, D.C. 20515

Mr. Chairman and Members of the Committee:

In her testimony before your subcommittee at the May 5, 1983 hearing on taxation of oil and gas producers, Alice M. Rivlin, Director of the Congressional Budget Office, suggested that one option for treatment of intangible drilling costs would be capitalization as depletable basis and recovery through cost depletion. As the only apparent justification for this suggestion, Ms. Rivlin states "this is the generally accepted practice that firms use for financial (as opposed to tax) reporting." This statement is a nonsequitur and fails to recognize that financial and tax reporting serve different purposes and frequently vary. This is especially true in the area of capital cost recovery. Thus, tax depreciation of machinery and equipment is on a fiver-year basis; whereas in most cases for financial reporting purposes the actual anticipated life is used.

As pointed out in the paper submitted to your subcommittee by the American Petroleum Institute, the appropriate cost recovery alternative to expensing of intangible drilling cost would not be financial accounting rules, but the rules provided through the Accelerated Cost Recovery System (ACRS). Five-year ACRS treatment with investment tax credit is available for assets similarly situated and similar expenses incurred in other industries.

Moreover, the revenue effects of repealing the expensing of intangible drilling costs as supplied by J. Gregory Ballentine, Deputy Assistant Secretary for Tax Analysis, in his testimony, while substantially less than Ms. Rivlin's revenue projection, used capitalization and recovery through cost depletion as the point of comparison. A more appropriate point of comparison would be that system available for recovery of other similar costs - five-year ACRS treatment. We would suggest that when that appropriate standard is followed, the revenue effects would be negligible in the long run and substantially lower even over the next two fiscal years.

Yours very truly,

John M. Mozola

J.M. Mozola
Tax Attorney

cc: American Petroleum Institute
Mr. J. R. McCarthy
Director of Taxation
2101 L Street, Northwest
Washington, D.C. 20037

Todd Exploration Company 320 South Boston
Tulsa, Oklahoma 74103 Phone 918/582-1979

COMMITTEE ON
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WAYS AND MEANS

May 10, 1983

Mr. John Salmon
Chief Counsel
Committee on Ways and Means
1102 Longworth Building
Washington, D. C. 20515

Dear Mr. Salmon:

Would you please submit our enclosed written testimony into the official record of The House Ways and Means Subcommitte on Oversight?

We appreciate the opportunity to express our views and to perhaps add a slightly different perspective to the subject.

Very truly yours,

TODD EXPLORATION COMPANY

Harry W. Todd

Harry W. Todd
President

HWT/srs

Encl.

May 10, 1983

Members of the House Ways and Means Subcommittee on Oversight
Congress of the United States
Washington, D. C. 20515

Gentlemen:

The one way we can reduce our dependence on foreign oil and the whims of an oil cartel is by having a strong and aggressive exploration program here in the United States. In order to make it strong and aggressieve, we must make it profitable to commit capital into the program.

Although we are a very small company within the oil industry, we are greatly affected by changes made through the works of your committee and others at the Federal level authorized to issue rules and regulations concerning the industry.

Our company is actively engaged in oil and gas exploration solely in Oklahoma. We are paid a monthly retainer fee to provide geological prospects exclusively for a Connecticut and a New York firm. Our growth income is derived from an over-riding royalty interest whenever oil or gas is discovered and produced from one of our geologic prospects. We are totally dependent on these two means of support.

It is therefore important to us that any bias in the form of profits or tax incentives in the system be maintained at the exploration level where the independent producers work, rather than at the gas pump level or at some other level in which the integrated companies have control. We do not wish to see another proliferation of corner gas stations and a dearth of drilling rigs.

In order to attract additional capital into exploration and to maintain economic health we strongly believe that the intangible drilling cost allowance, the depletion allowance and the royalty owners exemption be maintained. These items are vital in keeping investment dollars flowing into domestic exploration programs. Without them we can make little headway in becoming less reliant on foreign imported oil simply because investors who have the money will place it in more attractive, less speculative ventures. When this happens, we all lose.

Very sincerely,

TODD EXPLORATION COMPANY

Harry W Todd

Harry W. Todd
President

HWT/srs

WILLIAM S. WETZEL
GEOLOGIST — OIL PRODUCER
18 NORTH 8TH
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COMMITTEE ON
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WAYS AND MEANS

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[illegible]

April 24, 1983

FOR THE RECORD

Mr. John Salmon
Chief Counsel, Committee on Ways and Means
1102 Longworth Building
Washington, D. C. 20515

Dear Sir,

It has been brought to my attention that the Ways and Means Committee is considering changing the tax treatment now afforded independant oil producers over major integrated oil producers. I, as an independant oil producer would like to give you my reasoning in regards to changing these laws.

First let us look at the basic differences. I have only one source of income and that is the sale of raw crude oil to a pipeline company or to a refinery. That price is only regulated by the availability of the raw crude, if there is a surplus, I will receive less and should it be in short supply I receive more, (also paying more in windfall taxes). Basic logic tells you that the more I make the more I can spend in the local economy or in taxes, (none of these are bad for the country).

Next let us look at larger integrated companies, their main source of revenue is from the sale of finished products. Basic logic is that as a manufacturer of products, the cheaper you can buy basic material the cheaper you can sell the finished product. Volume and price of raw materials and the cost of processing dictate the price and profit of the finished product. Thus, if you are an integrated company your main concern is profit margin made on the finished product, all other costs are only a part of basic cost, profit is figured above that. It is important to keep all cost down but the bottom line is profit on the finished product.

The government by granting special tax treatment to small independant producers is insuring that they are able to compete with foreign oil sources. The refineries are going to buy the cheapest oil. If I as an independant can not make a profit off of finding and producing crude oil, I will not continue to look for new oil or to produce marginal wells as I do now. The large oil companies on the other hand will continue to opperate, as their existence is not dependant upon making a profit off of production of raw crude. Their only concern is the continued availability of crude at whatever price, (hopefully the cheaper the better, as volume of sales increases with lower cost of basic product).

WILLIAM S. WETZEL
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If the government wants to have a source of crude oil here at home they must realize that it is important that the independant oil producer is able to make a profit on raw crude, it is that simple.

When I as an independant oil producer make some money off of my efforts here in Stephens County, Oklahoma, in the search and production of crude oil, I in turn help provide jobs for people in all walks of life here in the city of Duncan, the state of Oklahoma, and the United States. If the government choses the foreign countries as their source of crude oil they are losing their guarantee of domestic sources as well as losing money derived from income taxes paid by all people employed directly or indirectly in the domestic oil industry.

To be so short sighted as to tax away all profit of independant producers, you are doing the nation a great injustice. Again let me say it is important for the nation to encourage a strong economic base, for growing crops, producing iron ore, educating young people, and the production of raw crude oil.

Think about it, without independant oil producers you will have to deal with foreign countries, and the profit they make will not be felt here in Duncan, Oklahoma, or many other places in the United States.

Your's Truly,

William S. Wetzel

cc/Senator David Boren
Rep. James R. Jones
Rep. Dave McCurdy